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Precursors to Potential Severe Core Damage Accidents: 1993
A Status Report

Appendices E and F

Prepared by
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Prepared for
U.S. Nuclear Regulatory Commission

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Abstract

Sixteen operational events that affected sixteen commercial light-water reactors during 1993 and that are considered to be precursors to potential severe core damage are described. All these events had conditional probabilities of subsequent severe core damage greater than or equal to 1.0×10^{-6}. These events were identified by first computer-screening the 1993 licensee event reports from commercial light-water reactors to identify those that could potentially be precursors. Candidate precursors were then selected and evaluated in a process similar to that used in previous assessments. Selected events underwent engineering evaluation that identified, analyzed, and documented the precursors. Other events designated by the Nuclear Regulatory Commission (NRC) also underwent a similar evaluation. Finally, documented precursors were submitted for review by licensees and NRC headquarters and regional offices to ensure the plant design and its response to the precursor were correctly characterized. This study is a continuation of earlier work, which evaluated 1969–1981 and 1984–1992 events. The report discusses the general rationale for this study, the selection and documentation of events as precursors, and the estimation of conditional probabilities of subsequent severe core damage for events. This document is bound in two volumes: Volume 19 contains the main report and Appendixes A–D; Volume 20 contains Appendixes E and F.

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PREFACE

The Accident Sequence Precursor (ASP) Program was established by the Nuclear Operations Analysis Center (NOAC) at Oak Ridge National Laboratory (ORNL) in the summer of 1979. The first major report of that program was published in June 1982 and received extensive review. Eleven reports documenting the review of operational events for precursors have been published in this program (see Sect. 4.0, Refs. 1-11). These reports describe events that occurred from 1969 through 1992, excluding 1982 and 1983. They have been completed on a yearly basis since 1987.

The current effort was undertaken on behalf of the Office for Analysis and Evaluation of Operational Data (AEOD) of the Nuclear Regulatory Commission (NRC). The NRC Project Manager for the project is P. D. O'Reilly.

The methodology developed and utilized in the ASP Program permits a reasonable estimate of the significance of operational events without the laborious detail associated with evaluation using event trees and fault trees down to the component level, while including observed human and system interactions. The present effort for 1993 is a continuation of the assessment undertaken in the previous reports for operational events that occurred in 1969–1981 and 1984–1992.

The preliminary analyses of the 1993 events were sent for review to the NRC headquarters staff, and the NRC regional staffs and licensees for those plants for which potential ASP events were identified. This is similar to the review process used for the 1992 events. In addition, the 1993 events were also independently reviewed as part of NRC's policy regarding probabilistic risk assessment (PRA) activities. All comments were evaluated, and analyses were revised as appropriate.

Reanalyses typically focused on and gave credit for equipment and procedures that provided additional protection against core damage. These additional features were beyond what has been normally included in past ASP analyses of events. Therefore, comparing and trending analysis results from prior years is more difficult because analysis results before 1992 are likely to have been different if additional information had been solicited from the licensees and incorporated. For 1993 the total number of precursors identified is less than that of past years. This is due at least in part to incorporating feedback on equipment, systems, procedures, etc., such that events initially identified as potential precursors with a conditional core damage probability somewhat greater than 10^{-6} were reanalyzed resulting in a value less than 10^{-6}, which is the threshold for rejection.

The operational events selected in the ASP Program form a unique data base of historical system failures, multiple losses of redundancy, and infrequent core damage initiators. These events are useful in identifying significant weaknesses in design and operation, for trends analysis concerning industry performance and the impact of regulatory actions, and for PRA-related information.

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FOREWORD

This report provides the 1993 results of the Nuclear Regulatory Commission's (NRC's) ongoing Accident Sequence Precursor (ASP) Program. The ASP Program provides a safety significance perspective of nuclear plant operational experience. The program uses probabilistic risk assessment (PRA) techniques to provide estimates of operating event significance in terms of the potential for core damage. The types of events evaluated include initiators, degradations of plant conditions, and safety equipment failures that could increase the probability of postulated accident sequences.

The primary objective of the ASP Program is to systematically evaluate U.S. nuclear plant operating experience to identify, document, and rank those operating events that were most significant in terms of the potential for inadequate core cooling and core damage. In addition, the program has the following secondary objectives: (1) to categorize the precursor events for plant specific and generic implications, (2) to provide a measure that can be used to trend nuclear plant core damage risk, and (3) to provide a partial check on PRA predicted dominant core damage scenarios.

In recent years, licensees of U.S. nuclear plants have added safety equipment and have improved plant and emergency operating procedures. Some of these changes, particularly those involving use of alternate equipment or recovery actions in response to specific accident scenarios, can have a significant effect on the calculated conditional core damage probabilities for certain accident sequences. In keeping with the practice initiated last year, the 1993 preliminary ASP analyses were transmitted to the pertinent nuclear plant licensees and to the NRC staff for review. The licensees were requested to review and comment on the technical adequacy of the analyses, including a depiction of their plant equipment and equipment capabilities. Each of the review comments received from licensees and the NRC staff was evaluated for reasonableness and pertinence to the ASP analysis in an attempt to use realistic models and data. All of the preliminary precursor events were reviewed, and the conditional core damage probability calculations were revised where appropriate. The objective of this review process was to provide as realistic an analysis of the significance of the event as possible. As a result, the 1993 ASP significant precursor conditional core damage probability results are somewhat lower than would have been calculated with the methods used in previous years. Although this will make year-to-year comparisons somewhat more difficult, it is an important step toward more realistic identification of significant events and conditions. In addition, consistent with the recommendations of the NRC's interoffice PRA Working Group, each of the analyses has been independently peer reviewed. This review provided a quality check of the analysis, ensured consistency with the ASP analysis guidelines, and verified the adequacy of the modeling approach and appropriateness of the assumptions used in the analysis.

The total number of precursors (16) identified for 1993 is less than previous years. This decrease is due in part to consideration of additional plant-specific mitigating equipment and recovery measures that were not considered in the previous years' analyses.

The four most important precursor events for 1993 involved failure of equipment in the plant switchyard (auxiliary transformer), failures of multiple service water system valves (two units), and clogged suppression pool strainers at a boiling-water reactor.

Charles E. Rossi, Director
Safety Programs Division
Office for Analysis and Evaluation
of Operational Data

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Appendix E:

Resolution of Comments on the Preliminary 1993 ASP Analyses

E.0 Introduction

This appendix contains the comments received from the applicable licensees and the Nuclear Regulatory Commission (NRC) staff for each of the potential precursors. The comments for each potential precursor are listed and discussed in docket number order, where the docket number refers to the plant that reported the problem. Comments are further separated between licensee and NRC comments. Only comments considered pertinent to the accident sequence precursor analysis are addressed. Comments simply pointing out grammatical or spelling errors were addressed in the revision of the analyses, but are not listed or addressed in this appendix. The reanalysis of some potential precursors resulted in the elimination of the event from the final set of precursors contained in Appendix A of this report. These events are noted in Table E.1.

Table E.1 List of Comments on Preliminary ASP Analyses

Event No.	Plant	Event description	Page
213/93-S01,** 213/93-006, 213/93-007	Haddam Neck	Degradation of MCC-5, Pressurizer PORV, and Emergency Diesel Generator	E.1-1
265/93-010, 265/93-012	Quad Cities 2	Emergency Power System Unavailable	E.2-1
289/93-002	Three Mile Island 1	Both Residual Heat Removal Heat Exchangers Unavailable	E.3-1
293/93-004	Pilgrim	Weather-Induced Loss-of-Offsite Power, Pressure Vessel Pressure/Temperature Limits Violated	E.4-1
293/93-013*, 293/93-014*	Pilgrim	NA	E.5-1
293/93-022*	Pilgrim	NA	E.6-1
313/93-003	Arkansas Nuclear One, Unit 1	Both Trains of Recirculation Inoperable for 14 h	E.7-1
316/93-007	Cook 2	Reactor Trip with Degraded Auxiliary Feedwater	E.8-1
331/93-010*	Duane Arnold	NA	E.9-1
334/93-013	Beaver Valley 1	Dual-Unit Loss-of-offsite Power	E.10-1
339/93-002	North Anna 2	Auxiliary Feedwater Disabled After Reactor Trip	E.11-1
341/93-014*, 341/93-015*	Fermi Unit 2	NA	E.12-1
370/93-008	McGuire 2	Loss-of-Offsite Power and Failure of an MSIV to Close	E.13-1
373/93-002*, 373/93-003*	LaSalle 1	NA	E.14-1
373/93-015	LaSalle 1	Scram and Loss-of-Offsite Power	E.15-1

*This event eliminated from set of final precursors.

**This denotes AIT report 213/93-80.

Introduction

E.1 AIT 213/93-80, LER Nos. 213/93-006, -007

E.1.1 Licensee

Reference: Letter from J. F. Opeka, Northeast Utilities System, to U.S. Nuclear Regulatory Commission, dated September 7, 1994.

E.1.1.1 General Comments

The licensee provided three general comments and 35 specific comments pertaining to the preliminary ASP analysis and documentation. In addition, the licensee provided information concerning design changes made at Haddam Neck after the June 27, 1993 event occurred. The three general comments and related specific comments are addressed first, followed by specific comments that provided clarifying information on Haddam Neck design and operation but had no impact on the analysis results. The remaining specific comments are then addressed. Comments are paraphrased in some cases for brevity.

Comment 1:

An allowed recovery time for MCC-5 substantially greater than the 30 min assumed in the preliminary ASP analysis is more realistic. Even assuming 30 min, the Human Reliability Analysis models and the IPE report use human error probabilities a factor of 5 to 10 lower than the ASP values. This comment was elaborated in specific comments 16, 23 and 30.

Comment 23 provided situation-specific allowable recovery times for MCC-5: 30 min to prevent an RCP seal LOCA, 35 min for feed and bleed initiation, and 6.6 hours to prevent core uncovery following multiple RCP seal LOCAs with AFW available.

Response 1:

The analysis has been revised to address the potential nonrecovery of MCC-5 in two time periods (1) before 30 min for HPI following a transient-induced LOCA and for feed and bleed initiation, and (2) before 1 h to prevent an RCP seal failure (see the response to general comment 3). The median response time used in the preliminary analysis (10 min) has been maintained. This time period includes 6 min for diagnosis and transit time and the 4 min required during the actual event for an operator at MCC-5 to recover power to the bus. This response time is assumed to be applicable to the direct recovery of MCC-5 and the recovery of charging and CCW via alternate means, which may be attempted if MCC-5 cannot be quickly recovered.

The 10 min value is somewhat longer than the 6 min estimated by the licensee in specific comment 16, and somewhat shorter than a 16 min value that can be estimated based on a distribution of transit times in response to a faulted EDG (another important component) included in "Electric Power Recovery Models," J.W. Read and K.N. Fleming, *Proceedings of the International Meeting on Probabilistic Safety Assessment, PSA '93*, January 26-29, 1993. It should be noted that Haddam Neck procedure E-0, Reactor Trip or Safety Injection, provides only indirect indication of a loss of MCC-5 until step 16.

Comment 2:

The preliminary ASP analysis assumes AFW flow control is dependent on MCC-5 and uses an unrealistically high probability for operator failure to control AFW, given nonrecovery of instrument air. This earlier plant design was revised during Appendix R and station blackout improvements; AFW flow indication is currently powered from 120-V ac vital buses. Given a loss of MCC-5, AFW flow control is available in the control room through manipulation of the hydraulically-operated AFW pump steam admission valves. The estimated time to SG overfill is 70-80 min, which provides ample time to gain control of SG level. In a conversation with ORNL and NRC personnel on August 26, 1994, the licensee noted that these hydraulic valves are routinely used to control SG level during startup and shutdown. This comment was elaborated in specific comment 27.

Response 2:

The analysis has been revised to reflect this comment. Control of AFW flow is now assumed to be essentially nominal following a loss of MCC-5.

Comment 3:

The Haddam Neck RCP seal design is unique in that it uses a flow restricting orifice that limits maximum seal leakage to 50 gal/min per pump. Given multiple catastrophic seal failures, a core uncovery time of 6.6 h is estimated, assuming AFW is available. The generic RCP seal LOCA model used in the ASP analysis is too conservative. Specific comments 30 and 31 provided additional information.

Response 3:

The ASP seal LOCA model for Westinghouse plants has been retained in the analysis, because questions raised during the NRC's ISAP review concerning the legitimacy of the 50 gal/min/pump maximum seal leakage have not been resolved. While the ASP seal LOCA model assumes a higher seal leakage than 50 gal/min/pump, one HPI pump still provides success. The ASP model assumes that the RCP seals will begin to fail one hour after loss of seal injection and thermal barrier cooling instead of the one-half hour assumed by the licensee. This is offset by the assumption that HPI is required within one-half hour of the seal failure for core cooling success.

E.1.1.2 Specific Comments Regarding Haddam Neck Design and Operation

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Comment 1:

Numerous specific comments and clarifications (comments 1-12, 15, 17, 19, 20, 22, 28, 29, 32, 33, and 34) were provided regarding the decision to test the MCC-5 ABT, component power supplies, "training" of systems and system design, plant-specific nomenclature, feed and bleed capability, plus changes made at the plant because the event occurred that reduce the dependence on MCC-5, improve its reliability, and reduce its importance to risk.

Response 1:

The analysis documentation has been revised to incorporate licensee clarifications to the extent practical, when those clarifications were considered appropriate. A separate paragraph describing plant changes because the event was added at the end of Additional Event-Related Information.

Comment 2:

Haddam Neck Specific Comment 13. Component cooling water flow to the RCP seals is not lost upon loss of MCC-5 alone, provided instrument air (via service air) is readily restored. However, for a LOOP, neither the charging pumps nor the component cooling water pumps are automatically started. Emergency operating procedures direct the operator to start the charging and CCW pumps. Once the CCW pumps are started, no other action is needed to re-establish RCP seal cooling. Hence, restoration of RCP seal cooling is not a "recovery" action, but a proceduralized step (step 13 of procedure E-0). On the time frame to implement step 13, given a LOOP and RCP trip (several minutes), thermal shock is not expected.

Response 2:

Response to Haddam Neck Specific Comment 13. The analysis has been revised to delete the discussion of thermal shock to the RCP seals. Recovery of CCW has been addressed in conjunction with recovery of MCC-5 (see general comment 1).

Comment 3:

Haddam Neck Specific Comment 14. Start of the second service water pump is desirable but not necessary for safe shutdown loads, given service water isolation valves SW-MOV-1 and SW-MOV-2 are both closed.

Response 3:

Response to Haddam Neck Specific Comment 14. The analysis description has been revised to clarify the requirement for manual closure of SW-MOV-1 and SW-MOV-2.

Comment 4:

Haddam Neck Specific Comment 18. Based on best-estimate transient analyses, the pressurizer PORV setpoint will not be challenged on a loss-of-offsite power with auxiliary feedwater available. Therefore, RCS pressure relief is not necessary absent unusual circumstances.

Response 4:

Response to Haddam Neck Specific Comment 18. The current ASP models assume the PORV challenge rate is 0.04 following a LOOP, which would address PORV lift only under unusual circumstances.

Comment 5:

Haddam Neck Specific Comment 21. The equation [p(9C | 11C) + ...] appears to be in error. The second term should include p(EDG A) rather than p(9C | 11C).

Response 5:

Response to Haddam Neck Specific Comment 21. A typographical error was made in the equation. The second term should include p(EDG A).

Comment 6:

Haddam Neck Specific Comment 24. There are three air compressors powered by MCC-5. The success criterion based on post-trip control air loads is one of three compressors. The instrument air equipment failure probability is insignificant given MCC-5 recovery.

Response 6:

Response to Haddam Neck Specific Comment 24. The analysis has been revised to assume that instrument air is recovered once MCC-5 is recovered.

Comment 7:

Haddam Neck Specific Comment 25. The nominal failure rates used in the ASP analysis are conservative with regard to plant-specific data incorporated into the PRA/IPE. Notwithstanding the EDG failure at 22 h, the EDGs have been very reliable at Haddam Neck. Per the IPE, the combined EDG failure to start, failure to run, and maintenance unavailability is 0.04 per demand verses 0.05 and 0.057 in the ASP analysis.

Response 7:

Response to Haddam Neck Specific Comment 25. The second EDG failure probability (0.057) used in the ASP program is the probability that the second EDG will fail, given failure of the first EDG. The product 0.05×0.057 (2.9×10^{-3}) thus incorporates dependant failure effects. Utilizing an independent failure probability of 0.04 along with the common cause failure to start (1.06×10^{-4}) and failure to run (1.8×10^{-3}) from Table 3.3.4-1 of the Haddam Neck IPE results in an overall failure probability for both EDGs of 3.5×10^{-3}, slightly higher than the failure probability used in the ASP analysis. The ASP failure probability has been retained.

Comment 8:

Haddam Neck Specific Comment 26. Using an EDG failure probability of 0.04 for both EDGs, [the expression in the section "EP-Emergency Power"] is requantified as $(0.04 \times 0.04 \times 0.8) + 2.4 \times 10^{-3} = 3.7 \times 10^{-3}$.

Response 8:

Response to Haddam Neck Specific Comment 26. The licensee requantification ignores dependent failure effects as described in the response to comment 25. The overall emergency power failure probability developed in the ASP analysis addresses dependent failure effects.

Comment 9:

Haddam Neck Specific Comment 35. The conditional core damage probabilities (included in the preliminary analysis) have been requantified. ... The results of Northeast Utilities' reanalysis indicate the conditional core damage frequency to be approximately 1.7×10^{-6}, about two orders of magnitude below the preliminary ASP value of 2.4×10^{-4}.

Response 9:

Response to Haddam Neck Specific Comment 35. The preliminary ASP analysis has been revised based on these and other comments. The revised core damage probability in included in the analysis provided in this report.

E.1.2 NRC Comments

Reference: Memorandum from G. M. Holahan, Director, Division of Systems and Safety Analysis, Office of Nuclear Reactor Regulation, to C. E. Rossi, Director, Safety Programs Division, Office for Analysis and Evaluation of Operational Data, September 9, 1994.

Comment 1:

The last term of the equation developed in the analysis for the failure probability of the ABT should include p(EDG A) instead of p(9C | 11C).

Response 1:

A typographical error was made in the equation. The second term should include p(EDG A).

Comment 2:

The probability of not recovering a LOOP in the short term (0.24) does not appear to have been addressed in the analysis.

Response 2:

This probability was omitted from the preliminary analysis. The conditioning event tree used to model LOOPs in the final analysis specifically addresses this probability.

Reference: Note to L. Nicholson, Region I, from B. Raymond, Senior Resident Inspector, Region I, dated August 26, 1994.

Comment 1:

Bus 5 is the MCC-5 preferred power source unless Bus 8 is not operable. The ABT selector switch was not normally positioned to Bus 6 if EDG-2A was the only component out of service.

Response 1:

The analysis description has been revised to reflect this comment.

Comment 2:

Clarifications were provided concerning the operation of front-line systems described in Additional Event-Related Information.

Response 2:

The analysis description has been revised were applicable.

Comment 3:

EDG failure is not expected to occur (because of insufficient service water flow if only one EDG starts). Insufficient EDG cooling could occur if river temperatures are high, and there is a failure to isolate turbine building loads.

Response 3:

The analysis description has been revised to reflect this comment.

Comment 4:

The ABT design [at the time of the event] included a 0.25 sec time delay to give preference to one supply in the event both diesels loaded simultaneously.

Response 4:

The analysis description has been revised to reflect this comment. This has essentially no affect on the analysis due to the variance in EDG loading times.

Comment 5:

Manual actions to restore power to MCC-5 would take 10 min "or less." A realistic estimate is less than 5 min.

Response 5:

A median recovery time of 10 min has been retained in the analysis, as described in the response to licensee general comment 1.

Comment 6:

The statement under "MCC-5 Failure and Restoration" in Modeling Assumptions concerning the equal likelihood that bus 5 or bus 6 will reach rated voltage first does not take into account the circuit time delay relays.

Response 6:

The fact that time delays existed in the ABT circuitry has been included in the analysis description. This has essentially no affect on analysis results because of the variance in EDG loading times.

Comment 7:

The probability of failing to reestablish control air following a loss of MCC-5 may be too high, if it is based on the assumed failure of a single air compressor. Success of two of the three air compressors at Haddam Neck will provide system requirements.

Response 7:

The revised analysis assumes instrument air is reestablished when MCC-5 is recovered. The impact of multiple air compressors failing to start is considered small compared with the probability of not recovering MCC-5.

Comment 8:

This comment provided information concerning the effect of loss of MCC-5 on AFW flow control and the potential for SG overfill.

Response 8:

Based on comments provided by the licensee concerning the potential use of the hydraulically-powered AFW turbine pump steam admission valves for AFW flow control (licensee general comment 2), AFW flow control following a loss of MCC-5 is considered to be essentially nominal in the revised analysis.

Comment 9:

MCC-8 can be powered from an emergency bus by local closure of the MCC-8 supply breakers. Charging is available following a LOOP with an assumed loss of MCC-5 with local manual actions.

Response 9:

The potential recovery of charging for RCP seal injection has been addressed in conjunction with the recovery of MCC-5, as described under "Seal LOCA" in Modeling Assumptions.

Comment 10:

Feed and bleed with the charging pumps and pressurizer safety valves can be established following a LOOP with loss of MCC-5. Local actions to repower MCC-8 and align MOVs would be required.

Response 10:

Feed and bleed using the charging pumps and pressurizer safety valves is not believed to be viable. This was confirmed in licensee specific comment 32.

Comment 11:

High pressure sump recirculation using the charging pumps is possible with a LOOP coincident with a loss of MCC-5. Local manual actions would be required to realign MOVs from the charging injection phase to the sump recirculation phase.

Response 11:

The ASP analysis assumes HPSI and charging are unavailable for HPI following a LOOP with a loss of MCC-5 unless MCC-5 is recovered or MCC-8 is repowered. High pressure sump recirculation is assumed available if HPI is recovered.

E.2 LER No. 265/93-010, -012

E.2.1 Licensee Comments

Reference: Letter from John L. Schrage, Commonwealth Edison, to William T. Russell, Director, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, dated September 8, 1994.

Comment 1:

ASP sequences 67 and 69 appear to be invalid despite modification of the models to address the potential use of the SSMP and RCIC for high-pressure makeup. These sequences appear to assume that low-pressure systems are unavailable because long-term ac power recovery occurs too late to prevent core damage. However, the analysis assumes that the Unit 2 EDG was available for an average of 7.5 h before failure, and the use of ADS and LPCI as an alternate to high-pressure injection would be possible.

Response 1:

Sequences 67 and 69 in the ASP models assume that recovery of ac power is required for successful ADS and use of low-pressure systems for injection. Even if low-pressure injection was initially successful, it would be lost once both EDGs failed.

Note that sequences 67 and 69 for case 2b incorrectly considered the use of the SSMP for high pressure makeup in the preliminary analysis, although bus 14-1 is not powered for this case. The probabilities for sequences 67 and 69 have been revised to reflect the unavailability of the SSMP (this had no effect on analysis results).

Comment 2:

The preliminary analysis used an average lifetime of 7.5 h for the Unit 2 DGCWP during the 7-month period based on the assumption that the pump was failed after the last surveillance run. This assumption is conservative because the pump may have been capable of continuing to run, but an accurate estimate of the pump's remaining life following the surveillance run does not appear to be feasible.

Response 2:

The assumption regarding average lifetime may or may not be conservative, depending on the actual oil consumption during the monthly tests compared to that during an extended run. The assumption is considered reasonable for a probabilistic risk assessment-type analysis.

Comment 3:

The preliminary analysis assumes for the dominant sequence (case 2b, sequence 83), that recovery of offsite power must occur before battery depletion (at 11.5 h) to prevent core damage. The preliminary analysis for the dominant sequence uses probability estimates of 0.66 and 0.23, respectively, for failing to recover offsite power in the short-term and before battery depletion. ... these values appear to have been multiplied in the calculation to give a total probability of 0.15 for failing to recover offsite power before battery depletion This value appears to be overly conservative, however, when compared to the value calculated using site-specific data for the Quad Cities IPE.

The analysis for the Quad Cities IPE, based on NUREG 1032, gives 0.03 as the probability of failing to restore offsite power within 11.5 h (attachment B to the Commonwealth Edison comments provided additional details). ... Use of the value of 0.03 for the probability of failing to restore offsite power would appear to significantly reduce (by a factor of 5) the calculated core damage probability for the dominant sequence.

Furthermore, the assumption that recovery of offsite power must occur before battery depletion to prevent core damage is conservative. At 11.5 h, decay heat would be reduced. ... water level would not drop to the top of active fuel until ~14.6 h after initiation of the event ...

Response 3:

The likelihood of failing to restore offsite power in the ASP model for Quad Cities is also estimated using data from NUREG-1032. The plant-centered, grid, and severe-weather groups and their recovery groups are the same as used in the Quad Cities IPE. The ASP model assumes an extremely severe weather group SS3, however, with an initiating event frequency of 0.002/site-year. This frequency is higher than the frequency of long-duration LOOPs (0.001/site-year at 19 h) included in NSAC-166, "Losses of Offsite Power at U.S. Nuclear Power Plants through 1990" (1991), but NSAC-166 does not include the long-term unavailability of offsite power at Turkey Point following hurricane Andrew in 1992. The assumption of an extremely severe weather group SS3 along with the above groups places Quad Cities in cluster 2, which is similar to the IPE.

The ASP analyses distinguish the different type of LOOPs (plant-centered, grid-related, etc.) and estimate LOOP frequencies and nonrecovery probabilities for each type in terms of Weibull distributions developed from data in Appendix A to NUREG-1032 for each LOOP type instead of from the cluster data. This allows different types of LOOPs observed in operating experience to be specifically addressed.

Cases 2a and 2b in the ASP analysis consider dual-unit LOOPs. These are predominantly caused by grid- and weather-related LOOPs, which have lower frequencies but also lower probabilities of recovery than an "average" LOOP represented by the cluster frequency distributions. This is why the LOOP nonrecovery probability at 11.5 h is higher for cases 2a and 2b and why the LOOP nonrecovery probability for case 1 (which considers more easily recovered plant-centered LOOPs) is lower than that estimated using cluster 2 data directly. The LOOP nonrecovery probabilities for cases 1, 2a, and 2b are considered appropriate and have been retained.

The ASP analyses assume that core damage occurs at the time of battery depletion, because of loss of control and instrumentation power for plant monitoring, turbine pump control, and breaker operation. Although ac power may be recoverable after battery depletion, such recovery would involve substantial difficulty. The assumption of core damage at the time of battery depletion is considered reasonable.

Comment 4:

The preliminary analysis assumes a probability of 1.0 for operator failure to restore cooling water to the 1/2 EDG. This is based on a cited paper that gives an estimated probability of 0.26 that an auxiliary operator would report to the DG room within 10 min of an EDG trip while running or starting.

The model cited does not appear to be completely applicable to the problem with the 1/2 DGCWP failing to start, however. The LER noted that "... Operators, as part of training, dispatch personnel to the diesel generator whenever it is autostarted. This dispatch increases the likelihood that the inoperable DGCWP condition would have been promptly corrected." For these reasons, the probability of an operator reporting to the 1/2 EDG room within 10 min is estimated to be greater than the value of 0.26 given in the cited paper.

Response 4:

The likelihood of an operator reaching the 1/2 EDG room (which is remote from the control room) and restoring the 1/2 DGCWP within 5 to 10 min following a LOOP to prevent EDG failure from overheating is admittedly difficult to estimate. In this event, after reaching the EDG room and determining that the DGCWP had not started, recovery would require first moving the feed power selector switch to the bus 18 position (which would not start the pump) and then to the bus 28 position. While recovery may be possible if the EDG can run for 10 min without damage, it is not expected to be reliable. Although the model in the cited paper may not be completely applicable to Quad Cities, the low recovery probability that is implied is considered indicative of the likelihood of 1/2 DGCWP recovery if a LOOP had occurred (in the cited paper, the median response time is estimated at 12 min).

In addition, in the dominant sequence, the 1 EDG is also failed following a dual-unit LOOP. This failure would compete with the 1/2 EDG for resources and further lessen the chances for recovery success. For these reasons, the nonrecovery probability used in the preliminary analysis is considered reasonable and has been retained.

E.2.2 NRC Comments

None

E.3 LER No. 289/93-002

E.3.1 Licensee Comments

Reference: Letter from T. G. Broughton, GPU Nuclear to U.S. Nuclear Regulatory Commission, dated July 8, 1994.

Comment 1:

The SBLOCA initiating event frequency used in the preliminary ASP analysis… appears to have been the BWR frequency… instead of the PWR frequency…. The Generic SBLOCA initiating event frequency is based on data for the early 1980s and is not specific to TMI-1. The TMI IPE uses a SBLOCA mean frequency of 6.7×10^{-7}/h (5.87×10^{-3}/year)… Assuming a 3 h unavailability of HPR and 0.43 nonrecovery probability… use of the TMI-1 SBLOCA initiating event frequency… would result in a core damage frequency of 8.6×10^{-7} ….

Response 1:

The PWR SBLOCA frequency of 1.5×10^{-2}/year was used in the analysis. The ASP program employs grouped data for infrequent events, such as SBLOCA. Applying the ASP nonrecovery probability of 0.43 for PWR SBLOCA results in a nonrecoverable frequency of 6.5×10^{-3}/year, very close to the 5.9×10^{-3}/year frequency used in the TMI-1 IPE. In the ASP program, a yearly frequency estimate is converted into an hourly estimate by dividing by an average number of critical hours/year (assumed to be 6132 h/year). The following calculation illustrates the calculation of the SBLOCA frequency and SBLOCA probability for this event.

$$1.5 \times 10^{-2} \text{ SBLOCA/year} \times 1/6132 \text{ operating h/year}$$

$$\times\, 0.43 \text{ (fraction of SBLOCAs that are not recoverable)} =$$

$$1.05 \times 10^{-6} \text{ nonrecoverable SBLOCA/operating hour.}$$

$$1.05 \times 10^{-6} \text{ SBLOCA/operating hour} \times 3 \text{ h} =$$

$$3.2 \times 10^{-6} \text{ (SBLOCA probability used in the analysis of this event).}$$

Comment 2:

Initiation of RB sump recirculation is not expected to occur until 3 to 10 h after the start of a SBLOCA …. Since recovery from the cooler (ES) bypass would have taken < 30 min, the action would have been completed by the time actual recirculation was initiated. Therefore, the SBLOCA probability should be applied to 2.5-h unavailability of HPR instead of 3.0 h.

Response 2:

ASP analyses address a potential initiator during the entire unavailability period. While this may add some conservatism to an analysis, it has little effect on the overall results in this case.

Comment 3:

[O]perators are trained to assess the status of ES systems in the event of an accident. If there had been a LOCA during the time that the DH Service Coolers were isolated, it is likely that the control room (if not the individual who isolated the coolers) would have recognized immediately that a surveillance had been started which could have affected the Decay Heat Closed Cooling Water System (DCCW) ....

Response 3:

Experience indicates that inappropriate alignments of safety systems will not always be detected promptly under accident conditions. It is not obvious that a more rapid identification of the incorrect alignment would occur under the stress and confusion associated with an accident. For this reason, nonrecovery assumptions made in the preliminary analysis have been retained.

Comment 4:

Assuming an allowable response time of 2 h based on continuous operation of HPR and an actual recovery time of 20 min to correct the valve alignment (during the actual event), the nonrecovery probability would be reduced to 0.01. Although GPU Nuclear is unable to provide what we would consider to be the appropriate nonrecovery probability within the time constraints allowed by your schedule, we believe that 0.43 is too high.

Response 4:

The value "0.43" is the probability of nonrecovery of the initiating event. This value is applicable to the SBLOCA initiating event frequency, as described in the response to comment 1.

Comment 5:

The TMI plant design utilizes three HPI pumps that would be running following ES actuation with offsite power available. The third HPI pump would not have been affected by the simultaneous bypass of cooling water to both DHR Service Coolers ...

Response 5:

The ASP analysis assumes HPI (pre-recirculation) is not impacted by the bypassed DHR service coolers. The analysis assumes HPR is affected becasue of the impact of the unavailable coolers on the LPI and HPI pumps during piggyback operation, as described in comment 6.

Comment 6:

LPI pump operation at elevated process water temperature is not a concern. The LPI pumps are designed for operation at 300°F. Evaluation of the LPI pump operation at elevated cooling water temperatures indicates that the pump and bearings would have continued to operate for at least 2 h. Motor operation under these conditions would need to be confirmed. GPU Nuclear has declined to pursue further evaluation of the LPI pump motor because of: the vendor's estimate of five to seven weeks to complete the work, the cost, and the other factors ... which result in a [GPU estimated] core damage probability below 1.0×10^{-6}. However, based on engineering judgement, we feel that it is likely that LPI pump motor operation would continue for some period of time under LOCA conditions.

Response 6:

The ASP analysis assumed HPR would be unavailable following initiation of sump recirculation. The ASP analysis assumed that recovery of the bypassed DHR service coolers would be unlikely, since (a) the operators would not be cued to detect the misalignment until the heat exchangers were required to provide DHR during recirculation, (b) following switchover to sump recirculation, radiological protection requirements would make it more difficult to access and realign the necessary valves, and (c) operation of all the components required for HPR for the post-recirculation mission time (20-22 h) without component cooling is by no means assured.

Comment 7:

As a result of accounting for (the factors described in comments 1-6) including 2 h unavailability of LPI which is not confirmed, GPU Nuclear has calculated that the core damage probability for this event would be 1.7E-8, which is well below the ASP threshold of 1.0E-6. Without confirmation of LPI pump motor operation under LOCA conditions, our calculations … still result in a core damage probability below 1.0E-6…

Response 7:

See the responses to comments 1-6. The Modeling Assumptions section of the analysis documentation has been revised to clarify the assumptions used in this analysis.

E.3.2 NRC Comments

None

E.4 LER No. 293/93-004

E.4.1 Licensee Comments

Reference: Letter from E. T. Boulette, PhD, Boston Edison, to the U.S. Nuclear Regulatory Commission, dated June 17, 1994, BECo Letter 94-071.

Comment 1:

The scram was caused by a switchyard flashover, not a LOOP. Preferred offsite power was available for 42 min following the scram. The scram occurred as a result of load rejection caused by switchyard insulator flashovers due to wind-packed snow deposited during a severe coastal storm. The actual LOOP did not occur until 42 min after the scram event, during which time the SUT remained available.

Response 1:

Typically the ASP Program has selected events for analysis as a LOOP if the LOOP required the EDGs to be relied on for safeguards power for an extended period of time. In this event, only the preferred offsite power source was lost; the 23-kV line was available throughout the event. The 23-kV line is atypical because it is not utilized until an EDG has failed to load. Although the 23-kV line was available, it was not used because an EDG did not fail. The plant response was typical of what most plants would experience during a total LOOP. The ASP event tree for a LOOP is appropriate and was used with one modification; the 23-kV line was treated as another source of emergency power.

Although the LOOP occurred 40 min after the trip, the system success criteria remain unchanged. Therefore, the LOOP model used is appropriate for the event.

Comment 2:

No credit was given for manual starting of the EDGs before losing the SUT. The EDGs were started 27 min after the scram in anticipation of losing the SUT. No credit for this action appears in the NRC analysis.

Response 2:

Although the EDGs were started and loaded 15 min before the actual loss of the 345-kV lines, the EDG probabilities were left at their nominal values. This was done because the same basic failure mechanisms are in place regardless of whether the EDGs are started before or immediately after the LOOP. In either case, the EDG has to start. The only difference between the manual start and the potential automatic start from the LOOP is the elimination of the potential failure of the automatic signal. It was assumed that this did not significantly affect the EDG failure probability. It was also assumed that insufficient time was available between the time that the EDGs were started and when the LOOP occurred for significant recovery actions to be performed. As a result, the mean-time-to-repair of the EDGs was assumed to be unaffected by the 15-min period. Had the EDGs been started early enough that significant recovery actions could have been performed before the LOOP event, a modification of the EDG mean-time-to-repair could have decreased the conditional core damage probability for the event. However, the potential for an EDG paralleled to the grid to trip following the LOOP would also need to be addressed.

Comment 3:

Offsite power remained available from the 23-kV source as automatic backup to the EDGs. The design capability of the SDT to automatically backup the EDGs is not included. The SDT remained available throughout the event.

Response 3:

The 23-kV line is unusual because it is used after the EDGs fail to start. The original analysis reviewed by the licensee did not include this mitigation feature in the modeling. The Pilgrim IPE indicates 18 failures of the 345-kV lines between September 13, 1975, and February 21, 1989. Of these 18 LOOPs, 7 were caused by severe weather (as was the modeled event). In three of these severe-weather-induced LOOPs, the 23-kV line was also lost. Therefore, the conditional probability that the 23-kV line is lost, given that the 345-kV lines were lost due to a severe-weather-induced LOOP, was set to 0.43 (3/7). Because the 23-kV line would close in automatically following the failure of the EDGs, the EDG nonrecovery value was modified to include the 23-kV line. It was assumed that breaker failures and control system failures were not significant given the high unavailability of the line under these conditions.

Comment 4:

Only RHR is credited for providing long-term core/containment cooling, whereas the main condenser could have been recovered. In extreme cases, the direct torus vent is available for use.

Response 4:

Incorporation of suppression pool venting into the model (which was done for all BWR models) reduces the conditional core damage probabilities for those sequences involving long-term cooling by 2 orders of magnitude. As a result, these sequences no longer contribute to the overall conditional core damage probability for the event. Therefore, the recovery of the main condenser and use of firewater were not addressed in the revised analysis.

Comment 5:

The ASP analysis is dominated by a LOOP-initiated Station Blackout sequence, sequence 83. This sequence is considered unlikely due to the LOOP not being the initiating event, the manual loading of the EDGs not being credited, and the automatic capability of the SDT to provide backup to the EDGs.

Response 5:

The use of the LOOP model is addressed in response to comment 1. The modeling of the EDGs is addressed in response to comment 2. The modeling of the SDT is addressed in response to comment 3.

Comment 6:

Sequence 55 involves a stuck-open SRV, followed by loss of HPI and failure to depressurize. If an SRV sticks open, depressurization would be accomplished in time to prevent core damage whether or not HPI is successful. This was verified through use of the Modular Accident Analysis Program (MAAP) as referenced in our IPE report sent to the NRC on September 20, 1992. Therefore, this sequence is not a core damage sequence.

Response 6:

On page B.4-3 of the Pilgrim IPE it states that the success criterion for the automatic depressurization system (ADS) is three out of four valves. On page C.4-30 the failure rate for depressurization, given an inadvertent open safety/relief valve (IORV) and a stuck-open relief valve (SORV), is reduced because fewer valves would be required to open. This indicates that depressurization is required in this situation. On page C.4-27 the modeling of the two unpiped safety valves is described. It indicates that the response for the inadvertent opening of these two valves is similar to that of a medium-break LOCA. On page C.3-5 the description of the medium-break LOCA indicates that "breaks within this size range will depressurize the reactor slowly enough to require high pressure injection during the short term to avoid core damage (without depressurization and low pressure injection . . .)."

Subsequent to the issuance of the IPE, the licensee performed a Modular Accident Analysis Program (MAAP) analysis of a trip with one SORV and all HPI systems inoperable. The results of this analysis indicate that the reactor vessel will depressurize rapidly enough to allow LPI systems to inject, and as a result, prevent core damage. The licensee indicated that the previous analyses performed for the IPE were overly conservative. Because one or more SORVs will perform the same function as the ADS system, the ADS failure rate for sequences 49 through 55 was set to zero.

Comment 7:

Sequences 67 and 69 deal with loss of HPI leading directly to core damage. Neither sequence challenges the depressurization function nor the subsequent LPI function. Depressurization would have been initiated if HPI had failed in this event. In fact, sequence 69 is not applicable for the same reason as sequence 55 because depressurization would be successful for a SORV.

Response 7:

The ASP event tree for this event requires HPI success if (1) offsite power is not recovered in the short term and (2) emergency power fails. This is the case in both sequences 67 and 69. n these two sequences, offsite power is not recovered in the short term (first half hour), and the EDGs/23-kV line has failed. Offsite power will not be recovered until at least one half-hour into the event. Although long-term offsite power recovery appears in the event tree before the HPI systems to decrease the number of sequences, the HPI systems would have to operate before long-term offsite power recovery. In addition, no low-pressure systems are available in the first half hour because they are dependent on ac power. Therefore, in the first half hour, only HPCI and RCIC are available. They must operate to prevent core damage until offsite power is restored.

Incorporation of the 23-kV line results in the probability of sequence 67 and 69 dropping by a factor of 2.3. This results in these sequences having no significant impact on the conditional core damage probability for this event.

E.4.2 NRC Comments

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data, from Martin J. Virgilio, Acting Director, Division of Systems and Safety Analysis, Office of Nuclear Reactor Regulation, dated June 16, 1994.

Comment 1:

The Additional Event Related Information section mentions that the two safety-related 4160-V ac buses can receive power from the 23-kV offsite power line or the blackout diesel generator. The analysis includes the BODG but not the 23-kV line.

Response 1:

The 23-kV line is unusual because it is used after the EDGs fail to start. The original analysis reviewed by the licensee and the NRC did not include this mitigation feature in the modeling. Because the 23-kV line would close in automatically following the failure of the EDGs, the EDG nonrecovery value was modified to include the 23-kV line.

Comment 2:

The Pilgrim IPE does not take credit for the control rod drive pumps as a source of high-pressure makeup to the vessel.

Response 2:

In this event, the assumptions concerning CRD pump viability as a source of high-pressure makeup do not significantly impact the overall conditional core damage probability. However, information from the licensee indicated that although the CRD system was not credited in the IPE, subsequent evaluation has determined that it is a viable source of high-pressure makeup to the vessel.

E.5 LER Nos. 293/93-013, -014

The existing ASP models do not include the potential use of containment venting for decay heat removal if both RHR/SPC and RHR/SDC fail. The modeling for all BWR events was revised to incorporate this potential mitigation strategy. This was done by revising the dominant sequences involving failure of both the RHR cooling modes to also include failure to vent the containment.

Incorporation of suppression pool venting into the modeling of this event reduced the overall conditional core damage probability to $< 1.0 \times 10^{-6}$. This is below the cutoff value for precursors used by the ASP Program. Therefore, the event was not included in the report. Incorporation of licensee and NRC comments may have further revised the overall conditional core damage probability for this event. Because the overall conditional core damage probability was already less than the cutoff value, specific responses to these comments were not developed.

E.5.1 Licensee Comments

Reference: Letter from E. T. Boulette, PhD, Boston Edison, to the U.S. Nuclear Regulatory Commission, dated June 17, 1994, BECo Letter 94-071.

Reference: Letter from E. T. Boulette, PhD, Boston Edison, to the U.S. Nuclear Regulatory Commission, dated September 6, 1994, BECo Letter 94-096.

E.5.2 NRC Comments

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data, from Martin J. Virgilio, Acting Director, Division of Systems and Safety Analysis, Office of Nuclear Reactor Regulation, dated June 16, 1994.

Reference: Memorandum for Pat O'Reilly, Office for Analysis and Evaluation of Operational Data, from Neal K. Hunemuller, Events Assessment Branch, Office of Nuclear Reactor Regulation, dated August 4, 1994.

E.6 LER No. 293/93-022

The existing ASP models do not include the potential use of containment venting for decay heat removal if both RHR/SPC and RHR/SDC fail. The modeling for all BWR events was revised to incorporate this potential mitigation strategy. This was done by revising the dominant sequences involving failure of both the RHR cooling modes to also include failure to vent the containment.

Based on information contained in the Pilgrim IPE, the existing ASP model was revised to incorporate the BODG and the 23-kV offsite power line.

Incorporation of suppression pool venting, the BODG, and the 23-kV line into the modeling of this event reduced the overall conditional core damage probability to $< 1.0 \times 10^{-6}$. This is below the cutoff value for precursors used by the ASP Program. Therefore, the event was not included in the report. Incorporation of licensee and NRC comments may have further revised the overall conditional core damage probability for this event. Because the overall conditional core damage probability was already less than the cutoff value, specific responses to these comments were not developed.

E.6.1 Licensee Comments

Reference: Letter from E. T. Boulette, PhD, Boston Edison, to the U.S. Nuclear Regulatory Commission, dated June 17, 1994, BECo Letter 94-071.

Reference: Letter from E. T. Boulette, PhD, Boston Edison to the U.S. Nuclear Regulatory Commission, dated September 6, 1994, BECo Letter 94-096.

E.6.2 NRC Comments

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data, from Martin J. Virgilio, Acting Director, Division of Systems and Safety Analysis, Office of Nuclear Reactor Regulation, dated June 16, 1994.

E.7 LER No. 313/93-003

E.7.1 Licensee Comments

Reference: Letter from Dwight C. Mims, Entergy Operations Inc., to U.S. Nuclear Regulatory Commission, dated September 14, 1994 (Letter No. LTR-1CAN099403).

(Background) LER 313/93-003 reports that, when DHR/LPI pump B was placed in service for DHR, motor bearing temperature rose excessively. On testing, the bearing temperature rose to 190°F, and the pump was shut down and declared inoperable. The motor shaft was found to be mispositioned along the shaft axis resulting in excessive load on the motor bearing. It is reported that the shaft had been mispositioned during maintenance 3 months earlier. It is also reported that thermal expansion of the pump shaft contributed to the shaft mispositioning and loading of the motor bearing and that this problem would not have arisen while pumping ambient-temperature water during LPI operation. The redundant A train pump was unavailable for a total of 14 h when the B pump shaft was misaligned.

Comment 1:

(Summary) The combination of the shaft mislocation and thermal expansion of the pump shaft during recirculation would have caused failure of B pump perhaps 2 h into recirculation. During a small-/medium-break LOCA, recirculation might not be initiated until more than 7 h into the event.

During the 14 h that the A pump was declared inoperable, its breaker was racked out and tagged to permit routine maintenance activities, including "meggering" of its motor and oil sampling/changeout. During a small-break LOCA or other event demanding LPI pump operation, time would have been available to restore A pump to service before failure of B pump.

Response 1:

The ASP Program generally considers equipment as being unavailable during the time that it is reported as inoperable, unless information is available that identifies a specific shorter time period. Recovery of inoperable equipment is credited according to the methodology described in Sect. A.1.3 of NUREG/CR-4674, Vol. 17, *Precursors to Potential Severe Core Damage Accidents: 1992 A Status Report.*

It is possible to outline scenarios in which it would be simple to return an inoperable piece of equipment to service, but it is also possible to outline scenarios in which it would be more difficult. The IPE for ANO indicates that during a small-break LOCA, "[h]igh pressure recirculation requires recirculation to occur in as little as approximately one hour...." It is not clear that, during a small-break LOCA, the first priority of maintenance workers would be to restore LPI pump A to service; presumably, the incipient failure of B LPI pump would not be detected until recirculation operation was begun. It is possible, then, that only 1 or 2 h would be available for the restoration of pump A.

The ASP analysis of this event found that the failure appeared recoverable at the failed equipment and assigned a nonrecovery probability of 0.34. This value seems consistent with ANO individual plant examination values for ex-control-room recoveries that are somewhat complex and that must take place within 1 or 2 h.

E.7.2 NRC Comments

Reference: Memo from T. Koshy, Events Assessment Branch, Office of Nuclear Reactor Regulation, to P. D. O'Reilly, Office for Analysis and Evaluation of Operational Data, dated August 8, 1994.

No response required.

E.8 LER No. 316/93-007

E.8.1 Licensee Comments

Reference: Letter from E. E. Fitzpatrick, American Electric Power, to W. T. Russell, Director, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, dated June 28, 1994, AEP:NRC:1214.

Comment 1:

The problem with the AFW flow control valve was easily diagnosable from the control room, and the requisite recovery actions were proceduralized; therefore, a lower AFW nonrecovery probability is in order: "A nonrecovery factor of .04 should be applied to the specific auxiliary feedwater pump failure, ('ASP Models,' Appendix A to NUREG/CR-4674, Vol. 17, page A-5), since the recovery action occurs in the control room and is directed by the reactor trip response procedure...."

Response 1:

The approach used in the ASP Program to address observed degraded systems (e.g., a single failed train) does not revise the system nonrecovery probability because the additional components that could fail (resulting in a complete system failure requiring recovery) are not specifically enumerated in the ASP train-based models. This is different than a fault-tree based analysis, where specific components that could be recovered are identified on a cut-set by cut-set basis.

To explore the possibility that additional recovery credit could be provided using a fault tree modeling approach, a fault tree for the AFW system was developed. This fault tree assumed that AFW flow was required from one pump to two SGs, consistent with the Cook IPE. Assuming typical ASP conditional probabilities of 0.3 and 0.5 for failure of the third and fourth control valve to operate correctly (the Cook IPE multiple greek letter values are 0.23 and 0.69) and assigning a nonrecovery probability of 0.04 to cut-sets that consisted predominantly of control valve failures results in a conditional AFW system failure probability higher than that estimated using the normal ASP approach for degraded systems (up to a factor of 6 higher, depending on the treatment of cut-sets containing more than four control valves). For the purposes of this analysis, the normal ASP approach to modeling degraded systems has been maintained.

Comment 2:

Only two of the four MSIVs experienced the drifting reported in the LER, and therefore the steam supply to the MFWPTs was not threatened: "Had both of these [drifting MSIVs] eventually closed, steam still would have been available to supply the main feedwater pumps."

Response 2:

The probability of failing to recover main feedwater was revised to consider the probability that the remaining two MSIVs would have drifted in addition to the probability that the operators failed to reopen the valves. This results in a nonrecovery probability of 0.076, slightly higher than the nominal ASP value, 0.07.

E.8.2 NRC Comments

None

E.9 LER No. 331/93-010

E.9.1 Licensee Comments

Reference: Memorandum from K. D. Young, IES Utilities, to William T. Russell, Director, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, dated June 23, 1994.

Comment 1:

Licensee comments indicated that the "B" loop of the residual heat removal system (RHR) was operable during the event. The license event report (LER) stated that the plant was in a Limiting Condition for Operation (LCO) for planned maintenance on the RHR system. The LER did not state what maintenance was in progress. Plant staff confirmed that the maintenance involved the testing of MO-1940 ("B" RHR heat exchanger bypass valve). The maintenance had been completed and the valve returned to service ~3 1/2 h before the scram occurred. However, the RHR system was not administratively cleared from the LCO condition because the postmaintenance testing had not yet been performed. Subsequently, the testing was completed successfully.

Response 1:

Based on the information supplied by the licensee, the event no longer meets the criteria for a precursor event. Therefore, an analysis of the event was not included in the current report.

E.9.2 NRC Comments

Reference: Letter from Martin J. Virgilio, Acting Director, Division of Systems and Safety Analysis, Office of Nuclear Reactor Regulation, to Gary M. Holahan, Director, Safety Programs Division, Office for Analysis and Evaluation of Operational Data, dated June 23, 1994.

No response required. Event is no longer a precursor based on the information supplied by the licensee.

E.10 LER No. 334/93-013

E.10.1 Licensee Comments

Reference: Letter from J. D. Sieber, Duquesne Light Company, to the U.S. Nuclear Regulatory Commission, dated July 5, 1994.

Comment 1:

The tree structure does not take into account the Unit 1 Appendix R DAFWP. This pump is powered by the Emergency Response Facility Diesel Generator and can provide water to the steam generators during a station blackout coincident with failure of the steam-driven AFW pump. This would only affect sequence 55. Therefore, with credit for the DAFWP, the core damage frequency for sequence 55 would be reduced by about 54% to 5.5×10^{-6}, using the IPE data; the overall conditional core damage probability for the event would be reduced by ~10% to 5.6×10^{-5}.

Response 1:

The modeling of the event was modified to include the Unit 1 Appendix R DAFWP. Back-calculating from the data that the licensee provided, the failure probability of the DAWFP was 0.46. Using this value, the overall conditional core damage probability for the event would be reduced by ~10% to 5.6×10^{-5}.

E.10.2 NRC Comments

None

E.11 LER No. 339/93-002

E.11.1 Licensee Comments

Reference: Letter from James P. O'Hanlon, Virginia Electric and Power Company, to U.S. Nuclear Regulatory Commission, dated August 30, 1994.

Comment 1:

No significant additions or corrections to the evaluation.

Response 1:

No response required.

E.11.2 NRC Comments

None

E.12 LER Nos. 341/93-014, -015

The existing ASP models do not include the potential use of containment venting for decay heat removal if both RHR/SPC and RHR/SDC fail. The modeling for all BWR events was revised to incorporate this potential mitigation strategy. This was done by revising the dominant sequences involving failure of both the RHR cooling modes to also include failure to vent the containment.

Incorporation of suppression pool venting and the standby feedwater system into the modeling of this event reduced the overall conditional core damage probability to $< 1.0 \times 10^{-6}$. This is below the cutoff value for precursors used by the ASP Program. Therefore, the event was not included in the report. Incorporation of licensee and NRC comments may have further revised the overall conditional core damage probability for this event. Because the overall conditional core damage probability was already less than the cutoff value, specific responses to these comments were not developed.

E.12.1 Licensee Comments

Reference: Letter from D. R. Gipson, Senior Vice President Nuclear Generation, Detroit Edison, to U.S. Nuclear Regulatory Commission, dated August 12, 1994.

E.12.2 NRC Comments

None

E.13 LER No. 370/93-008

E.13.1 Licensee Comments

Reference: Letter from T. C. McMeekin, Duke Power Company, to U.S. Nuclear Regulatory Commission, dated September 5, 1994.

Comment 1:

Duke uses a probability of 0.025 for PZR PORV failing to close (essentially the same value used in the precursor analysis). The contractor multiplied its failure probability by a factor of 4 to account for the multiple PORV lifts during the LOOP event. However, it should be noted that the failure probability has already been calculated based on the number of PORV failures per number of pressure relief demands. A "demand" consists of a varying amount of cycles (based upon system conditions at the time of the event). Therefore, multiplying this failure rate by some factor to account for valve cycling does not seem reasonable.

In addition, ORNL combines the PORV and SRV valve failures into a single event and thus fails to take credit for operator action to isolate a failed PORV. This is an expected and required operator action.

Response 1:

The Duke probability of 0.025 is the failure rate for one of the three PORVs to close. Therefore the failure probability of one of the three valves to close used in the IPE is approximately 0.075 (other failure mechanisms are not incorporated into this value). The PORV/SRV failure rate used in the ORNL analysis was multiplied by factor of 4 to account for the excessive number of cycles the PORVs underwent during the event (> 21). Based on data derived from observed events, the exact increase in the failure to close probability is not known. The factor of four increase was based on consultation with a nuclear industry data analyst. The value of 0.12 used in the analysis is similar to the value used in the McGuire IPE.

The PORV/SRV reseat nonrecovery probability includes both hardware recovery and operator recovery actions. This would include the operator closure of the PZR PORV block valves following the failure of a PORV to close.

Comment 2:

Regarding the SGTR analysis, the contractor used some generic industry data per NUREG-0844 to calculate the tube rupture probability. Westinghouse has performed a McGuire specific analysis and has estimated that for most tube crack-growth rates, the probability of an individual tube burst at differential pressures greater than 2335 psid is about 0.1%. When all crack-growth rates are included, the probability is about 0.5%. The analysis also uses recent tube plugging data of five tubes per unit (or 1.25 cracked tubes per steam generator). Hence, the rupture probability becomes 5.5×10^{-4} (most growth rates) and 2.8×10^{-3} (all growth rates).

Response 2:

The comment does not discuss the distribution of the 5 tubes per unit that were found to be cracked. Because the distribution of tubes was not available, it was assumed that all five tubes were in the exposed SG. P_a was modified from 2600 psid to 2335 psid. This results in a C_i value of 0.011 instead of 0.014, which was used in the preliminary analysis.

Comment 3:

Duke considers the probability of 0.003 for failing to cooldown RHR to be too conservative. More credit for operator action should be taken because, based on our MAAP code results, they would have 10 h or more to respond to this event. Considering the large amount of time available and recognizing that several plant personnel would be involved in the event response, the human error probability should be considered negligible.

Response 3:

Due to the complex nature of establishing RHR in this circumstance, the probability of 0.003 is reasonable. This action would occur after the operators were unable to isolate the ruptured SG with the MSIVs. Therefore, the operators are in a situation where cooldown to RHR is more difficult. Therefore, the 0.003 value is felt to be appropriate.

Comment 4:

It is too conservative to assume that a loss of RHR leads to core damage, as shown in the ORNL event tree. Numerous options are available to the operator at this point (e.g., feed-and-bleed cooling, refilling of the BWST, etc.). These are given in the McGuire loss of RHR procedures.

Response 4:

Although numerous options are available, this would occur after the operators were unable to isolate the ruptured SG with the MSIVs. According to the McGuire IPE, human operator failure rates for the types of action cited in the comment are in the 10^{-2} range. Therefore, the value of 8.1×10^{-3} appears to be reasonable.

Comment 5:

We believe that the dominant accident sequence for this event is the classic blackout sequence with failure of the diesel generator, the SSF, and the recovery of offsite power, with an estimated conditional probability of ~3 to 4×10^{-5}.

Response 5:

This is consistent with the results of the ORNL analysis. Sequence 49, the dominant sequence, involves a blackout sequence with failure of the diesel generator, and failure to recover offsite power. The SSF failure, which affects the seal failure probability does not affect the results of the calculation due to the short battery lifetime assumed for McGuire (1 h). The ASP program assumes that core damage occurs when battery depletion occurs. Since battery depletion would occur at the same time a seal LOCA is assumed to occur, the seal LOCA probability is set to 0.0. As a result, sequence 48, the sequence that matches the dominant licensee sequence, does not occur in the calculational results. However, the seal LOCA occurrence is consistent with the ASP calculational results.

E.13.2 NRC Comments

None

E.14 LER Nos. 373/93-002, -003

The existing ASP models do not include the potential use of containment venting for decay heat removal if both RHR/SPC and RHR/SDC fail. The modeling for all BWR events was revised to incorporate this potential mitigation strategy. This was done by revising the dominant sequences involving failure of both the RHR cooling modes to also include failure to vent the containment.

Incorporation of suppression pool venting into the modeling of this event reduced the overall conditional core damage probability to $< 1.0 \times 10^{-6}$. This is below the cutoff value for precursors used by the ASP Program. Therefore, the event was not included in the report.

E.14.1 Licensee Comments

None

E.14.2 NRC Comments

None

E.15 LER No. 373/93-015

The existing ASP models do not include the potential use of containment venting for decay heat removal in the event that both RHR/SPC and RHR/SDC fail. The modeling for all BWR events was revised to incorporate this potential mitigation strategy. This was done by revising the dominant sequences involving failure of both the RHR cooling modes to also include failure to vent the containment.

E.15.1 Licensee Comments

None

E.15.2 NRC Comments

None

E.16 LER No. 410/93-010

E.16.1 Licensee Comments

Reference: Letter from B. R. Silvia, Niagra Mohawk, to the U.S. Nuclear Regulatory Commission, dated June 23, 1994, NMP2L 1478.

Comment 1:

(Summary) The preliminary ASP analysis bounded the significance of the event by assuming that HPCS would not be available if demanded because of potential low control voltages. This was done because no information was provided in LER No. 410/93-010 concerning expected control voltages during the HPCS vulnerability period. Measured 4.16-kV bus voltages over an extended period of time were obtained. Approximately 2% of these measured voltages were below a bus voltage of 4.14-kV, the minimum voltage to ensure HPCS operability for the conditions observed. Some data were also available regarding voltages on the 600-V ac HPCS bus. Examining both the 4.16-kV and 600-V measurement data sets, it was concluded that voltages were too low ~1 to 2% of the time.

Response 1:

Revision of the HPCS failure probability to reflect the 4.16-kV measured bus voltages results in an estimated core damage probability to $< 1 \times 10^{-6}$, which is the cutoff for events identified as precursors. The HPCS unavailability described in LER No.410/93-010 has been removed from the set of 1993 accident sequence precursors.

E.16.2 NRC Comments

Reference: Letter from Larry E. Nicholson, Region I, U.S. Nuclear Regulatory Commission, to P. D. O'Reilly, Office for Analysis and Evaluation of Operational Data, dated May 23, 1994.

Comment 1:

Add "under certain low-voltage conditions" to end of the last sentence in Sect. 0.1.2.

Response 1:

After evaluating the additional information provided by the utility concerning this event, the event has been removed from the set of 1993 accident sequence precursors.

Reference: Letter from OEAB, to P. D. O'Reilly, AEOD, dated May 23, 1994 (EAB Action Assignment 94-39).

No response required.

E.17 LER No. 412/93-012

E.17.1 Licensee Comments

Reference: Letter from J. D. Sieber, Duquesne Light Company, Beaver Valley Power Station, to U.S. Nuclear Regulatory Commission, dated July 5, 1994.

Comment 1:

For Case 1, the operator failure rate of 0.34 to manually load the ESF equipment and reset the MCCs appears to be too high. The ESF pumps can be loaded directly from the control room, and all of the Unit 2 emergency MCCs can be reset at the 480-V ac substations located in the emergency switchgear rooms. Based on this, we have a high confidence that power to the MCCs can be restored at one location, and it would not be necessary to go to each individual MCC. Therefore, the ASP recovery class R3 operator failure rate of 0.12 appears to be more reasonable to use. By using the 0.12 operator failure rate, a reduction of ~65% in core damage probability would result, and the total Case 1 conditional core damage probability for this event would then be 7.4×10^{-7}.

Response 1:

Due to the complex nature of the operator response required in this situation, a value of 0.34 appears reasonable. Following the transient-induced LOOP with a LOCA in progress, operators must manually start and align all of the ESF equipment. This must be done in a particular order to prevent damaging the EDGs. Cooling to the EDGs would be a top priority and would have to be accomplished in a few minutes. Following the start of the SW pumps, the HHSI pumps would need to be started. Other equipment would have to be manually realigned and started without overloading the EDGs. Given the number of actions required, with many of the actions outside of the control room, the short period of time to accomplish the actions, the high stress level that would encountered during a LOCA/LOOP event, and the high degree of coordination required, the 0.34 value may be optimistic.

Comment 2:

For Case 2 the event tree structure and the timing of the modeling assumptions are incorrect. For Unit 2 LOOP initiators resulting in a PORV/SRV LOCA, final safety analysis report analyses show that the time required for the RCS to increase to the PORV set point and then decrease to the SI set point following the opening of a PORV is ~50 s. This is based on a review of the LOOP and inadvertent relief valve opening analyses that conservatively take no credit for steam dump valves opening. This would provide adequate time for the EDGs to start and sequence on the charging/HHSI pumps, SI valve MCCs, EDG cooling valves, and AFW pumps and valves before the SI reset sequencer failures would occur. Therefore all essential equipment would have electrical power available and would either be running (pumps) or would actuate (valves) when the SI signal is either automatically generated or manually initiated for feed-and-bleed. Manual loading of only minor ESF loads that are not required until much later in the event (LHSI pumps) would be required.

Response 2:

The analysis was revised to incorporate the starting of the HHSI pumps by the blackout sequencer. When this is done, neither of these scenarios significantly contributes to the overall conditional core damage probability for the event. The calculation for Case 2 from the preliminary analysis was removed from the final analysis.

E.17.2 NRC Comments

Reference: Memorandum from Martin J. Virgilio, Acting Director, Division of Systems and Safety Analysis, Office of Nuclear Reactor Regulation, to Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data, dated June 16, 1994.

Comment 1:

The licensee's test data indicated a failure rate of 0.33.

Response 1:

The analysis assumed a failure rate of 1.0 for the sequencers. The test conditions may not adequately simulate the conditions that the relays may experience during actual conditions. The licensee comments on the event did not indicate that this assumption was overly conservative. Therefore, it was not revised.

Comment 2:

Our experience with reported reactor conditions indicates that there are occasionally SI signals generated during LOSP (loss-of-offsite power) events. Based on a search of the Sequence Coding and Search System, there were 9 cases of SI signal generation during the 55 LOSP events reported from 1987 to present. We, therefore, estimated the frequency of occurrence for the conditions of concern to be the LOSP frequency, 3.6×10^{-2}/year, times the fraction 9/55, giving a frequency value of 5.8×10^{-3}/year.

Response 2:

A review of the nine events noted in the comment revealed that not all of the events were actual conditions requiring SI to actuate. The following summarizes the nine events.

323/88-008 Diablo Canyon 2 - PWR

Reactor Trip and Subsequent SI Following an Electrical Ground on a Connector to Reactor Coolant Pump 2-2 due to Galling on the Threads of an Aluminum Stud

A reactor trip occurred due to electrical faults associated with reactor coolant pump 2-2 at 0717 hours. At 0746 hours (29 min after the trip) startup power was lost. The diesel generators started and loaded onto their emergency buses. At 0757 hours (40 min after the trip) an SI signal was initiated on SG 2-3 high steam-line pressure differential. At 0807 hours (50 min after the trip), the SI was terminated.

249/89-001 Dresden 3 - BWR

Turbine Trip and Reactor Scram on Stop Valve Closure Due to Slow Transfer of House Loads During Loss-of-offsite Power

At 0133 hours, a fault occurred within the 345-kV switchyard power circuit breaker (PCB) 8-15. As a result, the Unit 3 reserve auxiliary transformer was deenergized, causing a LOOP to Unit 3. The auto transfer of a 4-kV bus did not occur fast enough to prevent undervoltage trips of a reactor feed pump and a recirculation pump. When the standby recirculation pump started, reactor water level rose to the point that it generated a reactor trip signal. The main steam isolation valves (MSIVs) were closed. At 0138 hours, the isolation condenser and HPCI systems were manually placed in service for reactor pressure control. ADS and core spray were also available. Power was available from offsite via the unit auxiliary transformer. (The search results were interpreted such that initiation of the isolation condenser was counted as an SI initiation.)

324/89-009 Brunswick 2 - BWR

Manual Reactor Scram in Accordance with I&E Bulletin 88-07 due to Loss of Both Reactor Recirculation Pumps Following a Unit 2 Loss-of-offsite Power

At 2047 hours on June 17, 1989, a manual reactor scram was initiated on Unit 2 due to a loss of both reactor recirculation pumps. Both pumps tripped when troubleshooting on Unit 2 startup auxiliary transformer (SAT), which supplies power to the pumps, caused the SAT to trip. The diesels automatically started and loaded. Reactor pressure was controlled by the SRVs, the high-pressure coolant injection system (HPCI), and the reactor core isolation cooling (RCIC) system. The HPCI system was manually actuated at 2053 hours. (Manual actuation of the RCIC and HPCI systems met the search criteria specified.)

237/90-002 Dresden 2 - BWR

Reactor Scram Following Condensate Booster Pump Failure and Subsequent Loss-of-offsite Power

At approximately 1724 hours on January 16, 1990, an automatic Unit 2 scram occurred on a low reactor water level. At 1725 hours, the main turbine tripped. At 1726 hours, the reserve auxiliary transformer tripped due to an internal fault. Normal offsite power was lost when the generator tripped. The Unit 2 and 2/3 diesel generators automatically loaded on their buses as designed. By 1728 the MSIVs were closed. At 1930 hours, the isolation condenser was placed into service for pressure control. At 2000 hours, HPCI was manually placed into service to assist with pressure control.

029/91-002 Yankee Rowe - PWR

Reactor Scram/Turbine Trip and Loss-of-offsite Power due to Lightning Strike

At 2350 hours, a lightning strike resulted in the destruction of a lightning arrestor on the No. 3 Station Service Transformer and flashover of an insulator. As a result, all offsite power was lost, an automatic reactor scram and turbine trip occurred, and all three EDGs operated as designed. While attempting to normalize the emergency busses, an inadvertent SI actuation signal was initiated at 0155 hours. No injection of SI water occurred.

219/92-005 Oyster Creek - BWR

Reactor Scram and Engineered Safeguards Features Actuations Caused by Offsite Fire

A reactor scram and subsequent ESF actuations were caused by a turbine load rejection due to faults on the 230-kV transmission line at 1326 hours. The EDGs started and loaded. Two low-level alarms were received, and the isolation condensers were actuated. At 1329 hours, the reactor low-low level alarm was received and initiated both core spray systems. Offsite power was recovered at 1331 hours. However, the safety-related buses were not transferred to offsite power until the system reliability could be assured.

261/92-017 Robinson 2 - PWR

Unusual Event due to Loss-of-offsite Power and Reactor Trip

At 1007 hours a LOOP occurred due to a trip of the startup transformer. At 1009 hours, a turbine and reactor trip occurred. The EDGs started and loaded properly. A manual SI was initiated at 1018 hours due to the decrease in the pressurizer level. SI was terminated at 1037 hours.

293/93-022 Pilgrim - BWR

Loss of Preferred Offsite Power and Automatic Scram Resulting from Load Rejection at 100% Power

At 1134 hours a simultaneous loss of preferred offsite power and an automatic scram occurred as the result of a load rejection caused by an electrical storm. The EDGs started and loaded as required. At 1135 hours, the RCIC and HPCI systems were placed in service for pressure control.

334/93-013 Beaver Valley 1 - PWR

Unit 1 Reactor Trip and Required Shutdown, Dual-Unit Loss-of-offsite Power

Unit 1 was operating at 100% power, and Unit 2 was in a refueling shutdown condition. At 1507 hours, ten switchyard breakers opened. Unit 1 tripped as a result. Both Unit 1 EDGs started and loaded. The Unit 2 standby component cooling water pump started. The Unit 2 train A EDG started and loaded available loads, including the LHSI pump. The pump did not inject water into the RCS because valves were closed for refueling conditions. The B EDG was removed from service for refueling.

In the five events that occurred at BWRs, the isolation condenser or HPCI was placed into service to control system pressure. The systems were placed into service manually. In the four PWR events, the SI was not needed in three of the four events. At Diablo Canyon, the system was initiated on steam-line pressure differential pressure caused by the reactor coolant pumps tripping at different times. The SI system was not required to prevent core damage in this case. At Yankee Rowe, the system was inadvertently actuated when restoring offsite power. In this case too, the SI system was not required to prevent core damage. At Beaver Valley, the unit that had the SI actuation was defueled at the time. During the Robinson 2 event, the SI system was required to restore pressurizer level following an overcooling of the RCS and was manually placed in service. However, the SI system only operated for a short period of time (20 min). Long-term SI would not be required in this condition.

During the initial LOOP response at Beaver Valley 2, the blackout sequencers would operate (because they were not affected by the relay problems) and would start the EDGs and load most safeguards equipment, including the HHSI/charging pumps. Because the switchover to the recirculation mode would not be required, no additional operator actions would be needed in this situation. Therefore the sequencer "lock-up" problem is not a concern in this situation. For plants where the HHSI pumps are not started by the blackout sequencer, this situation could contribute significantly to the conditional core damage probability.

The event analysis was revised to incorporate a discussion of this issue, but due to the factors noted above, the conditional core damage probability was not revised.

Comment 3:

The LOSP-initiated sequences do not provide for any recovery of offsite power. The nominal values should be used.

Response 3:

Revision of the event analyses based on licensee comments, removed the LOSP-initiated case from the final report.

E.18 LER No. 413/93-002

E.18.1 Licensee Comments

Reference: Letter from D. L. Rehn, Vice President Catawba Nuclear Station, Duke Power, to U.S. Nuclear Regulatory Commission, dated August 1, 1994.

Comment 1:

Duke Power disagreed with the selection of the dual-unit LOOP as the initiating event that would lead to the functional failure of ESW. The licensee selected a failure of the operating "2A" ESW pump as the initiating event to analyze. In support of this selection, the licensee provided the following information:

- the ESW pump discharge valves are closed when their associated pump is not operating,
- the ESW pump discharge valve does not complete a closure stroke if commanded to open during the valve closure,
- the ESW pump discharge valve takes about 55 s to complete a closure or open stroke,
- the "2A" ESW pump had operated for 1015 h during the 7-month period of interest,
- a table of ESW pump operations indicated that each ESW pump is operated for about a week at a time each month during plant operations.

Response 1:

The event was initially modeled as a postulated dual-unit LOOP based on information concerning ESW valve operation included in the FSAR. Based upon the additional information provided by the licensee, the initiating event was changed to the failure of the "2A" ESW pump while the plant had offsite power available.

Comment 2:

The licensee stated that a nonrecovery factor for opening an ESW pump discharge valve obtained using an HCR Model would be about 0.1 instead of the 0.34 "generic" ASP value. The HCR Model was based upon having a total of 50 min of time available to perform recovery actions requiring about 20 min to complete.

Response 2:

The nonrecovery factor of 0.1 was incorporated into the analysis based on the HCR Model value proposed by Duke Power.

Comment 3:

The SSF failure probability used in the preliminary analysis was applicable to station blackout conditions. For conditions where offsite power is available, a more appropriate value is 0.06 (from Appendix A.18 of the IPE).

Response 3:

The SSF failure probability was revised to be consistent with the new modeling assumptions and utilized the licensee-developed value of 0.06.

E.18.2 NRC Comments

None

E.19 LER No. 440/93-011, -010

E.19.1 Licensee Comments

Reference: Letter from R. A. Stratman, Centerior Energy, to the U.S. Nuclear Regulatory Commission, PY-CEI/NRR-1838 L, dated August 5, 1994.

E.19.1.1 Analysis Case 1—Unavailability of Suppression Pool Cooling

Comment 1:

More credit should be given to containment venting for decay heat removal. The failure to vent the containment was modeled in the Perry PRA. For the Perry PRA, the probability of human error (associated with containment venting) was assumed to be the same regardless of sequence or initiating event. Failure to align containment venting was more dependent on equipment than human error. For transients and small LOCAs, the estimated failure probability for containment venting was 1.1×10^{-4}. For loss-of-offsite power, the failure probability was 1.4×10^{-3}.

Response 1:

Because of the high stress expected to be associated with a requirement to vent the containment, the ASP analysis assumed that operator error would be the dominant failure mode associated with venting and used a failure probability of 0.01. Use of this value is supported by the human error probabilities utilized in a number of BWR PRAs:

Plant	Probability of operator error associated with venting
Fermi	3.1×10^{-2}
Limerick	4.4×10^{-3}
Nine Mile Point 2	6.0×10^{-3}
Washington Nuclear 2	1.6×10^{-1} (conservative value)

A human error probability of 0.01 for failure to vent the containment has been retained in the ASP analysis. However, the conditional probabilities for sequences 13 and 41 were reduced to reflect the availability of injection sources separate from the suppression pool for RPV makeup before venting. [It should be noted that the nominal value for the combined operator error probability associated with failing to initiate RHR and containment venting in the ASP models is 1.0×10^{-5}. *Analysis of Core Damage Frequency: Internal Events Methodology*, NUREG/CR-4550, Vol 1, Rev. 1, January 1990, estimates a median probability of approximately 1.0×10^{-6} for this action with an error factor of 30 (lognormal distribution). The resulting mean value is 8.5×10^{-6}, quite close to the combined value used in the ASP analysis.]

Comment 2:

For transients and small LOCAs, several alternate injection systems are available to the operators in the event that emergency-core-cooling systems (ECCSs) fail. . . . A motor-driven feedwater pump starts on loss of the turbine-driven feedwater pumps. As the pump does not use steam, loss of the power conversion system (PCS) will not cause failure of the motor feedpump. . . . The source of water is the condenser and condensate system. The probability of failure of RPV injection with the motor feedpump was estimated (in the PRA) to be 9.5×10^{-3} (including human error).

For loss-of-offsite power, the B emergency service water (ESW) pump or diesel-driven fire pump can be used for RPV injection following successful short-term ECCS injection. Consideration of such injection sources should reduce the core damage frequencies for sequences 40, 41, 49, and 65.

Response 2:

The ASP BWR models utilize a failure probability for main feedwater (MFW) which was developed from industry average initiating event categories included in NUREG/CR-3862. This allows failures of the condenser and condensate system, which would result in the unavailability of all feedwater, to be addressed in the MFW failure probability. The frequency of reactor trip and the probability of PCS and MFW failure have been recalculated for Perry to address the potential availability of the motor-driven feedwater pump. Grouped initiator data (BWR Group T2, T3A, and T3B) from the Perry IPE were used to estimate the frequency of a transient with offsite power available (7.07/year) and the probability of loss of PCS (0.23).

The frequencies of initiator subgroups listed in Table 3.2-3 of NUREG/CR-4550, Vol 1, Rev. 1, were used to estimate the probability of loss of the condenser or condensate system given loss of PCS (0.28) (frequencies for BWR initiator subgroups are not provided in the Perry IPE; however, the frequencies for BWR initiator groups are very similar to those provided in NUREG/CR-4550, Vol. 1, Rev. 1). Because the condenser and condensate system must be operable for motor-driven feedpump success and because the motor-driven feedpump is expected to be quite reliable (p(fail) ~ 0.01), the probability of condenser or condensate system failure can be used as an estimate of the probability that all MFW is unavailable (including the motor-driven pump) given loss of PCS. (Note that the ASP models assume that PCS success results in successful core cooling. The ASP models are, therefore, somewhat optimistic because the core damage sequences associated with BWR initiator groups T3A and T3B are not addressed.)

The potential use of alternate injection sources such as the B ESW pump or the diesel-driven fire pump are addressed in the ASP models under the branch heading "RHRSW or OTHER." In the sequences noted in the comment, RPV injection is provided using HPCI or RCIC.

E.19.1.2 Analysis Case 2—Service Water Break with Loss of Motor Feedpump and Control Rod Drive (CRD) Problems

Comment 1:

Case 2 should include venting of the containment in the same manner as described above for Case 1.

Response 1:

See the response to Comment 1 for Case 1.

E.19.1.3 Analysis Flooding Sensitivity Study for Case 2

Comment 1:

As in Cases 1 and 2, additional credit for containment venting would decrease the core damage frequencies in sequences 12 and 22.

Response 1:

See the response to Comment 1 for Case 1.

Comment 2:

The Perry IPE considered flooding of the corridor on the 568-ft elevation of the auxiliary building. Although instrument racks for RHR A, B, and C and LPCS are located in this corridor, flooding of the racks was deemed not to affect the system's ability to inject water into the RPV. Therefore, more credit should have been given to short-term ECCS injection capability. This would have an effect on all four of the most significant sequences.

In addition, alternate injection using suppression pool cleanup in the short term followed by either ESW/RHR B or fire protection along with containment venting for the long term would decrease the core damage frequency for sequences 19 and 27.

Response 2:

Along with the auxiliary building, the 574-ft level of the control complex was also flooding; water in the control complex also reached a height of 5 in. A control complex flood height of 22 in. would fail the ECC pumps and result in loss of cooling water for the RHR pump seals and the RCIC, LPCS, and RHR pump room coolers. The combined effects of flooding in both the auxiliary building and the control complex would be the eventual loss of RCIC and the low-pressure injection pumps. The LPCS pump would presumably be the least vulnerable to failure, because only its room cooling would be lost if flooding of the instrument racks in the auxiliary building does not impact low-pressure ECCS pump performance. To reflect this, the flooding sensitivity analysis has been revised to consider the LPCS pump to be operable for injection. This had little affect on the sensitivity analysis results.

The potential use of alternate injection sources is addressed in sequences 17, 18, 25, and 26.

E.19.1.4 Analysis HPCS Sensitivity Study for Case 2

Comment 1:

The core damage frequency for sequence 13 would be decreased if credit were taken for alternate injection using either ESW/RHR B or fire protection for long-term injection following the failure of RCIC due to suppression pool heatup or strainer fouling. Containment venting should also be modeled . . . to remove decay heat.

Response 1:

The probability of containment venting failure in sequence 13 has been revised to 0.01 to reflect the potential realignment of RCIC suction to the condensate storage tank before venting. Sequence 13 assumes RCIC provides successful RPV makeup.

E.19.1.5 Analysis Flooding and HPCS Sensitivity Study for Case 2

Comment 1:

Items 1 and 2 for the flooding sensitivity study and item 1 for the HPCS sensitivity study apply also to the sensitivity study performed for flooding effects and HPCS combined.

Response 1:

See the responses for comments 1 and 2 to the flooding sensitivity study and comment 1 to the HPCS sensitivity study.

E.19.2 NRC Comments

Reference: Memorandum from G. M. Holahan, Director, Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation, to C. E. Rossi, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data, September 26, 1994.

No response required.

E.20 LER Nos. 498/93-005, -007

E.20.1 Licensee Comments

Reference: W. T. Cottle, Houston Lighting and Power, to U.S. Nuclear Regulatory Commission, Letter No. ST-HL-AE-4815.

Comment 1:

(Summary) South Texas reviewed the ASP analysis and performed similar calculations using its IPE models. South Texas obtained a total conditional probability of core damage that was lower than the ASP value by approximately a factor of 6. This was attributed to (1) credit given for use of the PD charging pump, powered by the Technical Support Center (TSC) EDG, to provide an alternate source of reactor coolant pump (RCP) seal injection; (2) the assumption that TDAFWP control, as well as necessary monitoring and control of other plant functions, could be maintained after loss of all dc control power; and (3) smaller electric power and TDAFWP nonrecovery values.

Response 1:

The analyis has been revised to address the potential use of the PD pump and the TSC EDG to provide RCP seal injection in the event of a station blackout.

The ASP models assume that core damage occurs once the batteries are depleted, because control power for breaker operation and TDAFWP control, as well as RCS instrumentation, is then unavailable. It is noted in the comments that loss of dc power is assumed to preclude EDG start during blackout sequences. The analysis has been revised to address potential dc bus load shedding, which could substantially prolong battery lifetime.

The ASP analysis has been revised to address the use of the PD charging pump for seal injection and also to consider the possibility of shedding dc loads to prolong battery life. Electric power nonrecovery has been adjusted to better model conditions at South Texas according to the ASP methodology. Values for operator nonrecovery of equipment were maintained consistent with ASP methodology. Consideration of these factors results in reduction of the estimated core damage probability to 1.2×10^{-5}, which is somewhat closer to the conditional core damage probability estimated by Houston Lighting and Power.

E.20.2 NRC Comments

None

E.21 LER No. 529/93-001

E.21.1 Licensee Comments

Reference: Comments received via fax from Arizona Public Service (Palo Verde), to U.S. Nuclear Regulatory Commission, on August 18 and September 15, 1994.

Comment 1:

In an SGTR, 5 h is an acceptable time for depressurization and the use of LPSI following a loss of HPSI, with no operator action. This is in lieu of the 15 min assumed in the IPE. In an earlier fax APS noted that this revision in the timing associated with depressurization was the result of analyses performed after the March 1993 tube rupture.

Response 1:

The analysis has been revised to address the additional time available for depressurization.

Comment 2:

Other comments were noted but were determined to have minimal effect on analysis results. In an earlier fax, APS noted that the IPE assumed that even if the SGTR was detected and isolated, throttling of HPSI or RWT refill would be required for success. This would increase the core damage probability by 7.7×10^{-6}.

Response 2:

The ASP analysis assumes operator actions to throttle HPSI are associated with the branch RUPTURED SG ISOL (success). No change to the analysis is considered necessary.

E.21.2 NRC Comments

None

Appendix F:

Licensee Event Reports and Augmented Inspection Team Reports Cited in Appendixes A, B, and C

F.0 Introduction

This appendix contains the licensee event reports (LERs) and augmented inspection team (AIT) reports that are cited in appendixes A, B, and C. The LERs are ordered by docket and LER number. The AIT reports follow the LERs and are ordered by docket number. Table F.1 lists the LERs and Table F.2 list the AITs contained in this appendix. The associated plant, the title of the LER or AIT, and the associated precursor designator is also included in the tables.

Table F.1 List of LERs

Event No.	Plant	LER No.	LER Description
213/93-S01,** 213/93-006, 213/93-007	Haddam Neck*	213/93-006	Emergency Diesel Generator Failure Resulting From Diode Assembly Short
		213/93-007	Pressurizer PORV Emergency Air Supply Pressure Decay Test Failure
265/93-010, 265/93-012	Quad Cities 2	265/93-010	1/2 Diesel Generator Cooling Water Pump Failure To Start Due To Original Design Deficiency
		265/93-012	U-2 Diesel Generator Cooling Water Pump Inoperable.
289/93-002	Three Mile Island Unit 1	289/93-002	Bypass of oth Decay Heat Service Coolers Due to Personnel Error
293/93-004	Pilgrim	293/93-004	Automatic Scram Resulting From Load Rejection at 100 Percent Reactor Power
313/93-003	Arkansas Nuclear One, Unit 1	313/93-003	Low Pressure Injection Pump Potentially Incapable Of Performing Its Recirculation Mode Function Due To Improper Pump/Motor Coupling Which Resulted From Inadequate Procedural Guidance
316/93-007	Cook Unit 2	316/93-007	Reactor Trip from Spurious Turbine Exhaust Hood High Temperature Trip
334/93-013	Beaver Valley Unit 1	334/93-013	Unit 1 Reactor Trip and Required Shutdown, Dual Unit Loss of Offsite Power.
339/93-002	North Anna Unit 2	339/93-002	Automatic Reactor Trip Initiated from a Turbine Trip Due to an Over Excitation of the Main Generator
370/93-008	McGuire Unit 2	370/93-008	A Unit 2 Reactor Trip Occurred Due To A Loss Of Offsite Power Caused By A Possible Unanticipated Environmental Interaction, Vendor Fabrication Deficiency, Deficient Documentation, Inadequate Surveillance Program, And An Inappropriate Action.
373/93-015	LaSalle Unit 1	373/93-015	Unit 1 Scram and Loss of Off-Site Power Due to Bus Duct Water Intrusion

Event No.	Plant	LER No.	LER Description
412/93-012	Beaver Valley Unit 2*	412/93-012	Emergency Diesel Generator Sequencer Circuit Deficiencies
413/93-002	Catawba Unit 1	413/93-002	Technical Specification 3.0.3 Entered Due to Inoperable Pump Discharge Valves
440/93-011, 440/93-010	Perry*	440/93-010	Reactor Shutdown Due to Service Water Pipe Rupture
		440/93-011	Excessive Strainer Differential Pressure Across the RHR Suction Strainer Could Have Compromised Long Term Cooling During Post-LOCA Operation
498/93-005, 498/93-007	South Texas Project, Unit 1	498/93-005	Standby Diesel Generator 13 Failure to Start
		498/93-007	Technical Specification Required Shutdown due to the Inoperability of an Auxiliary Feedwater Pump
529/93-001	Palo Verde Unit 2	529/93-001	Manual Reactor Trip Following a Steam Generator Tube Rupture

*An AIT Report is also included for this event. See Table F.2.

**AIT Report 213/93-80.

Table F.2 List of AITs

Event No.*	Plant	AIT No.	AIT Description
213/93-S01, 213/93-006, 213/93-007	Haddam Neck	213/93-80	Inspection of Two Loss of Offsite Power Events and a Loss of Motor-Control-Center-5
412/93-012	Beaver Valley Unit 2	412/93-81	NRC Augmented Inspection Team Regarding the Failure of the Emergency Diesel Generator Load Sequencers
440/93-011, 440/93-010	Perry	440/93-06	Perry Unit 1 Service Water Pipe Break

*See Table F.1 for LERs associated with these events.

LER No. 213/93-006
Haddam Neck

NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Haddam Neck

DOCKET NUMBER (2): 0 5 0 0 0 2 1 3

PAGE (3): 1 OF 0 6

TITLE (4): Emergency Diesel Generator Failure Resulting From Diode Assembly Short

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 5	2 5	9 3	9 3	— 0 0 6 —	0 0	0 6	2 2	9 3		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 6

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)	X	50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME: Gary H. Tylinski, Senior Engineer

TELEPHONE NUMBER: AREA CODE 2 0 3 — 2 6 7 - 2 5 5 6

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
E	E K	S P P	X 9 9 9	Y						
E	E K	F A N	I 0 1 6	Y						

SUPPLEMENTAL REPORT EXPECTED (14)

☐ YES (If yes, complete EXPECTED SUBMISSION DATE) ☒ NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

ABSTRACT

On May 25, 1993, at 1330 hours, with the plant in Mode 6 (Refueling) the "A" Emergency Diesel Generator was manually shut down after 22 hours of a planned 24 hour endurance run at full rated load. Erratic diesel output and abnormal kilowatt, kilovar and ampere indications prompted the unplanned shutdown. Investigations within the generator excitation cabinet revealed that two voltage suppression devices (selenium rectifiers) had shorted and that the cabinet exhaust fan was not running. The root cause of this event was lack of adequate cooling inside the excitation cabinet, resulting in the failure of the selenium rectifiers which initially led to an abnormal field voltage condition and ultimately a loss of generator field. Initial corrective action included the installation of new diode assemblies and ventilation fan motors for both generators. This is being reported under 50.73 (a) (2) (vii) since it was an event where a single cause or condition caused two independent trains (EG2A and EG2B) to potentially become inoperable in a single system (onsite AC power) designed to mitigate the consequences of an accident.

NRC Form 366 (9-83)

NRC Form 366A (9-83)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO 3150-0104 EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Haddam Neck	0 5 0 0 0 2 1 3	9 3	— 0 0 6	— 0 0	0 2 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

BACKGROUND INFORMATION

The purpose of the two Emergency Diesel Generators (EIIS Code: EK) is to provide emergency power to ensure vital engineered safeguards availability in the event normal station service power is lost. Each unit is capable of attaining synchronous speed, full voltage, and ready to accept load within 10 seconds of receiving a start signal and is capable of supplying full (2000 hour rating) power of 2850 kilowatts (kW) and 1750 kilovars (kvar)- at 4160 volts, 3 phase 60 cycles - within 30 seconds after receiving an emergency start signal.

During normal operation the emergency buses are supplied from the incoming 115 kV system. The emergency diesel generators are in standby. Low voltage on either emergency bus will initiate automatic actions that will isolate the emergency bus from offsite power, strip and lockout all nonessential loads, start the emergency generators, connect them to their respective emergency buses, and energize selected emergency loads. The emergency diesel generators will also automatically start on a Safety Injection Actuation Signal to ensure that power is available for safeguards equipment. They will auto start, run up to full speed and voltage but will not connect to the emergency bus unless a degraded voltage condition also occurs.

During monthly surveillance tests, the units are manually slow started. Then, once the field is manually flashed, they are manually synchronized and loaded in parallel with offsite power. During semi-annual tests, the units are given a fast start with simultaneous field flashing and then manually synchronized and loaded in parallel with offsite power.

The excitation cabinet is not attached to the unit but is located nearby within the engine cubicle. This cabinet contains diesel generator controls and indications including bus voltmeter, generator voltmeter, generator ammeter, generator kilowatt meter, generator kilovar meter and generator frequency meter. The selenium rectifiers are located within the cabinet on an upper rear supporting shelf. This shelf is mounted about 12 inches below the cabinet ventilation fan housing. The selenium rectifiers are mounted on adjacent heat-sink plates along with the AC to DC inverting diodes and are electrically in parallel with them. They provide voltage suppression protection to the diodes. Six of these assemblies make up a three phase full-wave bridge. This bridge network (along with control power current transformers and power transformers and related controls) provides the DC power for the generator field. The two rectifiers which failed were in a common phase of the bridge.

NRC FORM 366A

*U.S.GPO 1988-0-824-538/455

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Haddam Neck	0 5 0 0 0 2 1 3	9 3	— 0 0 6	— 0 0	0 3 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The 24 hour test was a licensee initiated test based upon NUMARC guidance and industry recommendations. Aggressive load profiles were selected to exceed our accident requirements in both real power kW) and reactive power (kvar) level. This was considered a shakedown test to verify long term operability of the machine.

EVENT DESCRIPTION

On May 25, 1993, at 1``0 hours, with the plant in Mode 6 (Refueling) the "A" Emergency Diesel Generator (EDG) was manually shut down after 22 hours of a planned 24 hour full rated load endurance run in parallel with the grid. Operators at a location remote from the diesel building noted a sudden change in the sound of the EDG as well as cyclic area lighting dimming in synchronism with the engine drones. They quickly responded and upon arrival to the EDG room they observed that the unit sounded stable but appeared to be running somewhat slower and loaded down. A burning smell similar to propane was noted. The local meter indications showed approximately 1000 kW (down from a previous 2850 kW) and reactive power exceeding 2000 kvar IN (versus a previous 1750 kvar OUT) and amperage exceeding 800 amps (versus a previous 440 amps). The generator output breaker was immediately tripped and the engine was shut down. The abnormal condition is believed to have existed for less than one minute.

Test department personnel found the generator exciter field (AC supply) breaker tripped and very warm. After a general inspection of the assorted equipment in the room, the engine was restarted and an attempt was made to excite the generator. When the field was flashed, output voltage only reached about 2000 volts versus a nominal 4160 volts and then dropped to zero. The propane-like smell was again noticed in the area of the excitation cabinet. Two (of six) selenium rectifiers were found shorted in a common phase of the three phase bridge which converts AC to DC to supply the generator field. The excitation panel ventilation fan was found to be not running.

The "B" EDG excitation cabinet ventilation fan was inspected at 0900 on May 26, 1993 and also found failed. The "B" unit was declared inoperable until its rear exciter cabinet covers were removed to provide adequate ventilation. The "B" EDG was returned to operable status at 1840 on May 26, 1993.

NRC FORM 366A (9-83)

*U.S.GPO 1986-0-624-538/455

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Haddam Neck	0 5 0 0 0 2 1 3	9 3	— 0 0 6	— 0 0	0 4 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The "A" EDG scheduled maintenance activities then proceeded while further investigations and component testing relative to the failures continued. The manufacturer of the voltage regulator / excitation equipment and a generator design consultant were contacted for recommendations on inspections and testing to assess the existence or magnitude of other damage. Thorough testing of generator and excitation system components revealed no other signs of overheating or breakdown of other components.

During the course of troubleshooting activities and investigations, potential contributors toward the selenium rectifier failures were identified. Some areas within the excitation cabinet, including the vent fan motor and some of the rectifiers had accumulated a significant amount of dust. By original design, the fan is always energized and running. Additionally, there are no filters associated with the cabinet intake louvers. This results in continuous unfiltered air circulation which over time can accumulate dust on electrical and mechanical components. This may have lead to changes in thermal, electrical, and/or mechanical characteristics which, when combined, may have precipitated the failure of the rectifiers.

Another potential contributor is the conduit configuration between the generator housing and the excitation cabinet. These conduits route generator output and field cables to and from the excitation cabinet, but also provide a pathway for warm air to be drawn into the base of the excitation cabinet by the cabinet ventilation fan. This air would enter the conduit at temperatures somewhat higher than ambient, thus contributing to the elevated temperature in the vicinity of the rectifiers.

CAUSE OF THE EVENT

The root cause of this event was lack of adequate cooling inside the excitation cabinet, resulting in the failure of the selenium rectifiers which initially led to an abnormal field voltage condition and ultimately a loss of generator field. The failure mechanism is postulated to be the result of the combination of excessive heat generated due to the high electrical loading of the machine along with dust accumulation and loss of forced ventilation in addition to the age of the devices. It is uncertain whether both rectifiers failed together or one failed and overstressed the other until it failed as well.

NRC FORM 366A (9-83)

*U.S. GPO 1988-0-824-538/455

NRC Form 366A (9-83) — LICENSEE EVENT REPORT (LER) TEXT CONTINUATION — U.S. NUCLEAR REGULATORY COMMISSION — APPROVED OMB NO. 3150-0104 EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Haddam Neck	0 5 0 0 0 2 1 3	9 3	— 0 0 6 —	0 0	0 5 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

SAFETY ASSESSMENT

This event is considered reportable under the requirements of 10CFR50.73(a) (2) (vii) as an event where a single cause or condition caused at least two independent trains (EG2A and EG2B) to potentially become inoperable in a single system (onsite AC power) designed to mitigate the consequences of an accident.

To assess the safety significance of this event, a loss of normal power scenario consisting of a loss of offsite power and a single failure of one EDG was assumed, and the design basis accident electrical loading profile was compared to that of the 24 hour test load. It was determined that the required emergency safeguards equipment loading profile is well under the 24 hour test levels in real power and reactive power. However, Operations personnel are allowed to load the EDG up to full load after entering the post-LOCA sump recirculation phase. It was noted that the power factor was always much better (i.e. closer to 1.0) than that of the 24 hour test. The heat generated in the excitation cabinet is directly related to the power factor of the loads. A better power factor requires less field current thus generating less heat in the excitation cabinet. Despite the inoperable fan, there would be some natural convection through the side louvers and the fan vent on top of the cabinet.

Due to the expected lower cabinet temperatures, the EDG would perform its intended safety function well beyond the successful test period of 22 hours. If both EDGs operate post-LOCA, then the resultant load on each EDG would be lower still, and consequently so would the excitation system heat loads.

This event is considered moderately significant, in that a similar condition existed in both EDGs that could lead to generator excitation failure. Since the electrical loading of the 24-hour test is more severe than that anticipated during LOCA mitigation (especially if both EDGs are operating), it is not anticipated that both diesel generators would fail in the critical first few hours.

CORRECTIVE ACTION

Short term corrective action involve the following:

1. Installation of new diode assemblies (diodes, selenium rectifiers, mounting hardware and heat-sinks) and new ventilation fan motors for both generators.

NRC FORM 366A (9-83) — *U.S.GPO 1986-0-624-538/455

NRC Form 366A (9-83)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Haddam Neck	0 5 0 0 0 2 1 3	9 3	0 0 6	0 0	0 6 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

2. Prior to plant startup from the 1993 refueling outage, an air stop will be installed in the conduit which runs from the generator to the excitation cabinet.

3. Verification of fan operation as part of Operations Department routine activities.

Long term corrective actions include evaluation of the following :

1. Modification of the excitation cabinet ventilation fan control such that the fan runs only when the generator is operating.

2. Review of preventative maintenance practices for EDG exciter cabinet and other instrument and control cabinets for cleanliness and maintenance.

ADDITIONAL INFORMATION

The diesel generators are General Motors EMD 999 Systems comprising a Model 645E4 engine and a Model A-20-C2 generator. The selenium rectifiers were manufactured by International Rectifier Corporation and are model number 59-7006. The complete assembly including the selenium rectifier is model/part number 66-6811 8334736.

PREVIOUS SIMILAR EVENTS

NONE

NRC FORM 366A (9-83)

*U.S. GPO 1986-0-624-538/455

LER No. 213/93-007
Haddam Neck

NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Haddam Neck	0 5 0 0 0 2 1 3	1 OF 0 6

TITLE (4): Pressurizer PORV Emergency Air Supply Pressure Decay Test Failure

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
0 5	2 5	9 3	9 3	— 0 0 7 —	0 0	0 6	2 2	9 3		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 5

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
Susan K. Muik, System Engineer	2 0 3	2 6 7 - 2 5 5 6

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	L D	D R Y	P 0 5 0	NO		X	L D	R G	I 2 0 8	NO
X	L D	S O L	A 6 0 9	NO		X	A B	R V	C 6 3 5	NO

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

ABSTRACT

On May 25, 1993 at 0000 hours, with the plant in Mode 5 (Cold Shutdown) and performing a pressure decay test of the pressurizer Pilot-Operated Relief Valves (PORVs) emergency air supply system, it was determined that the pressure decay exceeded the Technical Specification acceptance criterion of 0.3 psi/hr. The problem was traced to a leak in the diaphragm assembly of one of the PORVs (PR-AOV-568). This leak was caused by both the inadequate sealing of the PORV diaphragm assembly and the failure of the PORV air supply pressure regulating valve (CA-PRV-836A). The failure of the air pressure regulating valve was caused by corrosion inside the valve due to water intrusion from the containment control air system. The moisture in the containment control air system was due to a malfunction of its air dryer. Corrective action includes the replacement of the PORV diaphragm assembly with one that has a configuration for tighter sealing, the replacement of the regulating valve, the blowdown of the air system to remove any remaining water, and repair of the air dryer malfunction. It is not known how long the PORV had been inoperable prior to this surveillance, but it is believed to have been longer than the ACTION time allowed. Therefore, this event is reportable under 10 CFR 50.73 (a) (2) (i) (B), since the plant had been in operation with a condition prohibited by the Technical Specifications.

NRC Form 366 (9-83)

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Haddam Neck	0 5 0 0 0 2 1 3	9 3	— 0 0 7	— 0 0	0 2 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

BACKGROUND INFORMATION

The primary purpose of the pressurizer Pilot Operated Relief Valves (PORVs), (EIIS Code: AB) is to limit Reactor Coolant System (RCS) pressure to below the pressurizer safety valve setpoint, thus limiting the operating frequency of the code safety valves. The air operated pressurizer PORVs (PR-AOV-568 and 570) receive their air supply from the containment control air system (EIIS Code: LD) and an air accumulator. The control room operators have the ability to open either PORV manually to establish a "bleed" path for use in the "feed-and-bleed" method of core cooling (feed via safety injection and bleed via the PORVs). This is required when the steam generators are not available for decay heat removal. The PORVs also open automatically on a two out of three high pressurizer pressure signal.

The control air system includes a 107 gallon emergency air accumulator to support PORV operation for the "feed-and-bleed" method of core cooling in the event of a failure of both non-safety related containment air compressors. The air supply lines which lead to the PORVs (Figure 1) are each provided with a pressure regulator (CA-PRV-836A & B), (EIIS Code: LD). These regulators reduce the air pressure being supplied from 120 psig to 85 psig. An air relief valve (CA-RV-838A & B) (EIIS Code: LD) is provided on each PORV operator to protect it from overpressurization in the event that the supply line regulator fails open. These relief valves are set to open at 100 psig (the same as the maximum design pressure of the PORV diaphragms).

The containment control air system consists of two air compressors rated at 29 CFM at 150 psig which operate in a lead/lag arrangement. The compressors discharge through a common header to a 400 gallon receiver. The air flows from the receiver, through a coalescing pre-filter, and into a heatless regenerating type desiccant dryer. The dry air then passes through a particulate filter and is supplied to the individual containment air loads via the air distribution piping.

The portion of the containment control air system that supplies air to the PORVs from the accumulator serves a safety related function. It is isolated from the remainder of the containment control air system by two safety related check valves.

NRC FORM 366A (9-83)

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Haddam Neck	0 5 0 0 0 2 1 3	9 3	— 0 0 7	— 0 0	0 3 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT DESCRIPTION

On May 25, 1993 at 0000 hours, with the plant in Mode 5 (Cold Shutdown) for a refueling and maintenance outage, while performing Surveillance 5.7-187, "PORV Emergency Air Supply Pressure Decay Test", it was determined that the pressure decay exceeded the test acceptance criterion of 0.3 psi/hr. The actual data reflected a pressure decay of 2 psi/hr. This surveillance tests the pressure retaining components of the PORV emergency air supply system boundary as required by Technical Specification 3.4.4, "Relief Valves".

The failure of the pressure decay test was traced to a leak in the diaphragm assembly of one of the PORVs (PR-AOV-568). This leak was caused by both inadequate sealing of the PORV diaphragm assembly and the failure of the PORV air supply pressure regulating valve (CA-PRV-836A). The failure of the regulating valve subjected the relief valve on the PORV operator to a pressure greater than its set lift pressure creating a primary air leak path, thus decreasing the availability of sufficient air in the accumulator. It also subjected the PORV diaphragm to its maximum design pressure creating another air leak path through the diaphragm seating surface into the containment atmosphere, again decreasing the availability of sufficient air in the accumulator.

The failure of the regulating valve was caused by corrosion inside the valve due to water intrusion from the containment control air system. The diaphragm of the failed brass regulating valve was covered with a powdery blue-green corrosion product when it was inspected. This corrosion caused a leak in the diaphragm allowing air to vent through the regulator eventually causing the pressure to equalize on both sides.

An investigation into the cause of the water in the air system identified a malfunction of the containment control air dryer. The dryer is a model 25HA4 manufactured by Pall Pneumatic Products Corp. The dryer malfunction was due to a faulty purge exhaust solenoid valve. The failure of this valve in turn caused the failure of the desiccant towers to switch from drying to regeneration. It is not known how long this condition may have existed. A moisture indicator is provided on the dryer to detect excess moisture by a color change. A high moisture indication was not evident since the indicator was inadvertently isolated from the outlet of the dryer. This misled operators during routine monthly containment entries to believe that the dewpoint reading was acceptable.

NRC FORM 366A (9-83)

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Haddam Neck	0 5 0 0 0 2 1 3	9 3	— 0 0 7 —	0 0	0 4 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Technical Specification 3.4.4 requires that the control air supply for the PORVs shall be demonstrated OPERABLE at least once per 18 months by verifying that the control air supply does not drop more than 0.3 psi in one hour when isolated from the containment control air system. The actual time of failure is unknown but is believed to have been longer than the time allowed by the Technical Specification ACTION statement.

CAUSE OF THE EVENT

The root cause of this event was due to a malfunction of the air dryer. This problem was compounded by a lack of indication of air dryer performance and a possible error in the valve lineup for the local instrumentation which could have allowed operators to detect the dryer malfunction and have it corrected.

SAFETY ASSESSMENT

Feed-and-bleed is an available means of cooling the reactor core to Residual Heat Removal (RHR) (EIIS Code: BP) entry conditions in the event that the steam generators are unavailable to remove core decay heat. It is postulated that the air compressors would not operate in the environment created by feed-and-bleed thus, emphasizing the importance of the safety related accumulator emergency air supply.

Although the use of main and auxiliary feedwater is the primary and preferred method of safe shutdown, feed-and-bleed remains critical to meeting the Probabalistic Risk Assessment (PRA) core melt frequency goal and is credited as an available safe shutdown method for the following applications:

1. Loss of main and auxiliary feedwater
2. High-energy pipe breaks
3. Internally generated missiles
4. Tornado missiles/wind protection

However, in this event only one of the two PORVs was rendered inoperable as a result of the regulator failure.

In a feed and bleed scenario, the relief valve on the PORV air operator would lift if overpressurized by a faulty air regulator. The relief valve would then bleed air from the accumulator until the low accumulator pressure alarm sounded in the control room. In this situation, the procedures direct the operator to close the affected PORV and open the other train. This operator action would restore the operability of the feed-and-bleed method within 30 seconds. Thus, the safety significance of this event is judged to be low.

NRC FORM 366A (9-83)

*U.S. GPO 1988-0-824-538/455

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/85

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

CORRECTIVE ACTION

Corrective actions that have been completed relating to this event include the following:

1. Replacement of the PORV diaphragm assembly which has a 12 hole configuration with one that has a 24 hole configuration for tighter sealing.

2. Conducting a thorough blowdown of the air system to remove any remaining water.

Corrective actions that are planned to be completed prior to startup from the 1993 refueling outage include the following:

1. Replacement of the pressure regulating valve.

2. Repair of the air dryer malfunction and its associated faulty purge exhaust solenoid valve.

3. Installation of a direct readout dew point monitor with alarm and control functions.

4. Revision of the plant procedures regarding operation of the containment control air dryers to provide additional guidance for proper system operation and performance monitoring.

ADDITIONAL INFORMATION

System	Component	Manufacturer	Model Number
LD	Air Regulator	ITT Conoflow (I208)	GFH25XT2365G
AB	PORV diaphragm	Copes-Vulcan (C635)	080815
AB	PORV cover	Copes-Vulcan	080812
AB	PORV base	Copes-Vulcan	080813
LD	Air Dryer	Pall-Trinity (P050)	25HA4
LD	Solenoid valve	ASCO (A609)	8210G7

PREVIOUS SIMILAR EVENTS

93-005-00

NRC Form 366A (9-83)

*U.S.GPO 1986-0-624-538/455

NRC Form 366A (9-83) | U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
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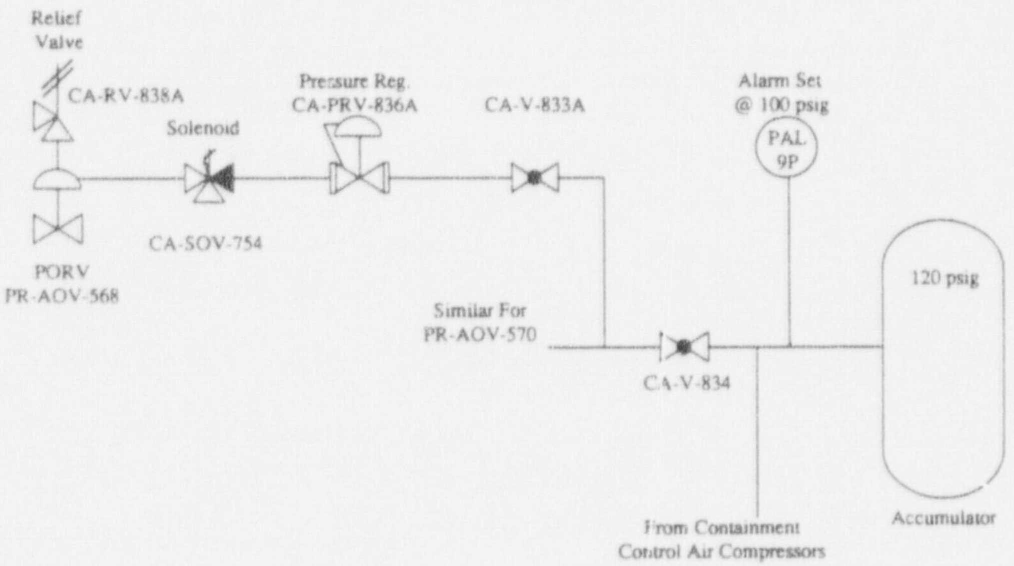
TEXT (If more space is required, use additional NRC Form 366A's) (17)

Figure 1



LER No. 265/93-010
Quad Cities

LICENSEE EVENT REPORT (LER)

Form Rev 2.0

Facility Name (1)	Docket Number (2)	Page (3)
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Title (4)

1/2 Diesel Generator Cooling Water Pump Failure To Start Due To Original Design Deficiency

Event Date (5)			LER Number (6)			Report Date (7)			Other Facilities Involved (8)	
Month	Day	Year	Year	Sequential Number	Revision Number	Month	Day	Year	Facility Names	Docket Number(s)
										0 5 0 0 0
0 4	2 2	9 3	9 3	0 1 0	0 0	0 5	1 8	9 3		0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)			
		___ 20.402(b)	___ 20.405(c)	___ 50.73(a)(2)(iv)	___ 73.71(b)
POWER LEVEL (10)	0 0 0	___ 20.405(a)(1)(i)	___ 50.36(c)(1)	___ 50.73(a)(2)(v)	___ 73.71(c)
		___ 20.405(a)(1)(ii)	___ 50.36(c)(2)	___ 50.73(a)(2)(vii)	___ Other (Specify in Abstract below and in Text)
		___ 20.405(a)(1)(iii)	___ 50.73(a)(2)(i)	___ 50.73(a)(2)(viii)(A)	
		___ 20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	___ 50.73(a)(2)(viii)(B)	
		___ 20.405(a)(1)(v)	___ 50.73(a)(2)(iii)	___ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER	
	AREA CODE	
Randy Charneski, Technical Staff Engineer Ext. 2175	3 0 9	6 5 4 - 2 2 4 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
B									

SUPPLEMENTAL REPORT EXPECTED (14)		Expected Submission Date (15)	Month	Day	Year
___ Yes (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e, approximately fifteen single-space typewritten lines) (16)

ABSTRACT:

On April 22, 1993, at 1322 hours, Unit Two was in the SHUTDOWN mode at 0 percent of rated core thermal power. At that time, Technical Staff personnel were performing 4kV Bus 23-1 Undervoltage Functional Test, QOS 6500-4. During performance of this surveillance the 1/2 Diesel Generator Cooling Water Pump (1/2 DGCWP) failed to start as required. An Emergency Notification System (ENS) notification was completed at 2145 hours on April 22,1993.

The root cause for the 1/2 DGCWP failing to start is a design deficiency in the Bus 28 breaker close logic that has existed since the plant was originally designed. This deficiency causes the breaker to lockup following an undervoltage condition. The design deficiency has also existed on the Bus 18 breaker control logic since the installation of modification M04-1/2-83-014 in 1985. However, the lockup on Unit One would only occur if the power selector switch was in the Bus 18 position. Corrective actions included a modification to add an undervoltage contact in the Bus 28 close logic to the 1/2 Diesel Generator Cooling Water Pump

This report is being submitted to comply with 10CFR50.73 (a)(2)(ii)(B).

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION					Form Rev 2.0
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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

PLANT AND SYSTEM IDENTIFICATION:

General Electric - Boiling Water Reactor - 2511 MWt rated core thermal power.

EVENT IDENTIFICATION: 1/2 Diesel Generator Cooling Water Pump failure to start due to original design deficiency.

A. CONDITIONS PRIOR TO EVENT:

Unit: Two	Event Date: April 22, 1993	Event Time: 1522
Reactor Mode: 1	Mode Name: Shutdown	Power Level: 0%

This report was initiated by Deviation Report D-4-2-93-029.

SHUTDOWN Mode (1) - In this position, a reactor scram is initiated, power to the control rod drives is removed, and the reactor protection trip systems have been deenergized for 10 seconds prior to permissive for manual reset.

B. DESCRIPTION OF EVENT:

On April 22, 1993, at 1322 hours, Unit Two was in the SHUTDOWN mode at 0 percent of rated core thermal power. At that time, Technical Staff personnel were performing 4kV Bus 23-1 Undervoltage Functional Test, QOS 6500-4. During performance of this surveillance the 1/2 Diesel Generator Cooling Water Pump (1/2 DGCWP) failed to start as required. After approximately two minutes, the Equipment Operator at the Unit 1/2 Emergency Diesel Generator [DG] [EK] took the 1/2 DGCWP Feed Power Selection Switch from the Bus 28 [BU] position through the NORMAL position to the Bus 18 position and then back to the Bus 28 position. The 1/2 DGCWP started when the switch was moved from the Bus 28 position. The Unit 1/2 DG was declared inoperable and troubleshooting began with Electrical Maintenance, Operations and Tech Staff personnel. At 2145 hours, a design deficiency was identified in the 1/2 DGCWP Bus 28 close logic circuitry that would not allow the pump to automatically restart if it had been fed from Bus 28 and received an undervoltage trip signal.

An Emergency Notification System (ENS) notification of this event was completed at 2145 hours on April 22, 1993, to comply with the requirements of 10CFR50.72 (b)(1)(ii)(B).

Quad Cities Station Interim procedure # 133 was written and successfully performed on April 23, 1993, to demonstrate the 1/2 DGCWP operability to Unit One. There were no other systems or components inoperable at the beginning of this event which could have contributed to the event.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION — Form Rev 2.0

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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

C. APPARENT CAUSE OF EVENT:

This Licensee Event Report is being submitted in accordance with 10CFR50.73 (a) (2) (ii) (B), which requires reporting any event or condition that resulted in the condition of the nuclear power plant, including its principal safety barriers, being seriously degraded, or that resulted in the nuclear plant being in a condition that was outside of the design basis of the plant.

The root cause for the 1/2 DGCWP not starting is a design deficiency in the Bus 28 breaker close logic that has existed since the plant was originally designed. This design deficiency would prevent the 1/2 DGCWP from auto-starting if it was running on Bus 28, received a Bus 28 undervoltage trip and subsequently power was restored to Bus 28.

The problem was introduced into the Bus 18 pump control logic during the installation of modification M04-1/2-83-014 in 1985. This modification added the 1/2 DGCWP Feed Power Selector Switch to address Appendix R concerns. However, the problem only exists for the Bus 18 feed if the selector switch is placed in the Bus 18 position. The Bus 18 position of the switch is not the normal lineup for the 1/2 DGCWP.

In addition, the following concerns were discovered during the investigation of this event:

1. Some electrical prints reviewed were found to be incorrectly or inadequately labeled.

2. Electrical drawing 4E-1351C does not show the internal breaker logic. This significantly hindered the detection of this design deficiency over the years.

D. SAFETY ANALYSIS OF EVENT:

The safety significance of this event is minimal. At all times the 1/2 DGCWP could have been started by taking the pump control switch to trip and then back to the auto after trip or close position. In addition, the original logic of the electrical feeds to the 1/2 DGCWP aligned the pump to be fed from Unit One at all times except when Bus 18 experienced an undervoltage condition. If Bus 18 was experiencing an undervoltage condition the feed to the pump would automatically transfer to Bus 28. If the pump was being fed from Bus 28 and an undervoltage condition occurred, the Bus 28 breaker would trip and the breaker would lock-up due to the anti-pump logic. If voltage was restored only to Bus 28, the pump control switch would have to be taken to the trip position or the power selector switch would have to be moved to the 18, normal or 28 position to clear the breaker anti-pump lockout.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION — Form Rev 2.0

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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

Assuming a worst case single failure, the plant design is required to safely handle a Loss Of Coolant Accident (LOCA) on one unit and provide normal shutdown of the other unit, coincident with a station Loss Of Offsite Power (LOOP). In the scenario with a LOCA on Unit Two coincident a loss of the Unit One 125 Volt DC battery system, the Unit Two Diesel Generator would fail to auto-start because of the loss of the Unit One 125 Volt DC battery system. The LOCA signal on Unit Two would cause the 1/2 Diesel Generator to load to Unit Two 4 kV Emergency Bus 23-1. Bus 28 would be available to power the Unit 1/2 DGCWP, however, the Bus 28 breaker would trip on a Bus 28 undervoltage and then lockup due to the anti-pump mechanism.

The cooling water pump would not transfer to Bus 18 because the 1/2 DG is powering Bus 23-1. The control room would receive annunciator A-4, Diesel Generator 1/2 Trouble on the 902-8 panel and would dispatch an EO to the 1/2 DG room as directed by procedure QCAN 902-8 A-4. In the 1/2 DG room, the EO would find alarm Diesel Cooling Water Pump Failure OR Diesel Cooling Water Pump Locked Out and would be directed by Procedure QCAN 2212-45 C-3 to place the power selector switch to the 28 position and manually start the pump.

E. CORRECTIVE ACTIONS:

The immediate corrective action was to declare the 1/2 Diesel Generator inoperable and begin troubleshooting. Permanent corrective actions involved the design and installation of partial modification M04-0-93-003A which added a Bus 28 undervoltage contact in the close circuit and changed the existing undervoltage contact in the trip logic to come off of the same relay as the contact installed in the close circuit of the Bus 28 feed to the 1/2 Diesel Generator Cooling Water Pump.

In addition the following corrective actions will be or already have been implemented:

1. Modification M04-0-93-003B will be designed to move the presently installed Bus 18 undervoltage contact to a common point in the close circuit to clear the close signal independent of the position of the power selection switch. This modification will be installed during refuel outage Q1R13 (NTS# 2652009302901).

2. Caution Cards have been placed on the 1/2 DGCWP Feed Power Selection Switch until Modification M04-0-93-003B is installed and tested.

3. Caution statements will be added to procedures identifying limitations with the power selection switch (NTS# 2652009302902).

4. Document Change Requests will be submitted to correct drawing deficiencies (NTS# 2652009302903).

5. Quad Cities Station has in place a Detailed System Walkdown Program (DSWP) to walkdown systems and correct drawing error/deficiencies.

6. The internal close circuit for both the Bus 18 and 28 feed breakers to the 1/2 DGCWP were verified to be wired per detail "A" of Quad Cities electrical drawing 4E-2657E on May 11, 1993.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION							Form Rev 2.0		
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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

F. PREVIOUS EVENTS:

There have been two previous event involving inadequate design with the Diesel Generator.

LER NUMBER	TITLE
04-02-92-014	1/2 Diesel Generator Outside Design Basis - Inoperable to Unit Two
04-02-87-001	1/2 Diesel Generator failed to auto start during C.S. Logic test from a blown fuse due to an electrical drawing error

G. COMPONENT FAILURE DATA:

There was no component failure identified with this event.

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LER No. 265/93-012
Quad Cities

LICENSEE EVENT REPORT (LER)

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Title (4)

U-2 Diesel Generator Cooling Water Pump Inoperable.

Event Date (5) Month	Day	Year	LER Number (6) Year	Sequential Number	Revision Number	Report Date (7) Month	Day	Year	Other Facilities Involved (8) Facility Names	Docket Number(s)
										0 5 0 0 0
0 6	0 1	9 3	9 3	0 1 2	0 0	0 6	3 0	9 3		0 5 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)

OPERATING MODE (9): 4

POWER LEVEL (10): 0 0 7

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	Other (Specify in Abstract below and in Text)
20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER AREA CODE	
Steve Davis, Tech Staff Group Leader, Ext. 2186	3 0 9	6 5 4 - 2 2 4 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
A									

SUPPLEMENTAL REPORT EXPECTED (14)

		Expected Submission Date (15)	Month	Day	Year
Yes (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single-space typewritten lines) (16)

A. ABSTRACT:

At approximately 1500 hours on June 1, 1993 Unit 2 was in the run mode at approximately 7 percent of rated core thermalpower. CECo concluded on June 1 through review of available information that the U-2 Diesel Generator [DG] Cooling Water Pump (DGCWP) [P] was inoperable during the period from February 16 to March 15, 1993.

The Unit 2 DGCWP was inoperable from February 16 to March 15 due to inadequate lubrication. The oiler piping was incorrectly assembled due to inadequate training on how to set and position this type of oiler.

Corrective actions include replacing the U-2 DGCWP, walkdowns to verify the adequacy of drawings/instructions used by Operations and Maintenance, and ensure proper installation of oilers and sightglasses on other plant equipment. Corrective actions also include training of Operations and Maintenance personnel, revision of maintenance lesson plans, and communication of lessons learned to other CECo facilities. A self-assessment was also chartered to look at craft capability, work package detail and other maintenance practices.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION — Form Rev 2.0

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Quad Cities Unit Two	0 5 0 0 0 2 6 5	9 3	-	0 1 2	-	0 0	0 2 OF 0 5

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

PLANT AND SYSTEM IDENTIFICATION:

General Electric - Boiling Water Reactor - 2511 MWt rated core thermal power.

EVENT IDENTIFICATION: U-2 Diesel Generator Cooling Water Pump Inoperable.

A. CONDITIONS PRIOR TO EVENT:

Unit: Two	Event Date: June 1, 1993	Event Time: 1500
Reactor Mode: 4	Mode Name: RUN	Power Level: 7%

This report was initiated by Licensee Report 265/93-012.

RUN Mode (4) - In this position the reactor system pressure is at or above 825 psig, and the reactor protection system is energized, with APRM protection and RBM interlocks in service (excluding the 15% high flux scram).

B. DESCRIPTION OF EVENT:

At approximately 1500 hours on June 1, 1993 Unit 2 was in the run mode at approximately 7 percent of rated core thermal power. CECo concluded on June 1 through review of available information that the U-2 Diesel Generator [DG] Cooling Water Pump (DGCWP) [P] was inoperable during the period from February 16 to March 15, 1993.

CECo determined on approximately April 22, 1993 that the 1/2 Diesel Generator was inoperable prior to this date due to design deficiencies described in LER 265/93-10.

As such, there were no operable DGs to Unit 2 during the period February 16 to March 15. During this period, Unit 2 was in the run mode until March 6 when Unit 2 entered a refueling outage. The removal of fuel from the core was completed on March 15.

Having no operable DGs during the period February 16 to March 6 while the mode switch was in run was contrary to Technical Specification (TS) 3.9.E.1. This TS states that if there are no operable DGs to a given Unit that an orderly shutdown of that Unit must be initiated and the reactor shall be in a cold shutdown condition within 24 hours. Having no operable DGs during the period March 6 to March 15 while the reactor was in cold shutdown was contrary to TS 3.9.E.3. This TS states that when the reactor is in cold shutdown or refueling mode a minimum of one operable diesel is required whenever any work is being performed which has a potential to drain the vessel, Secondary Containment is required or a core or containment cooling system is required. Removal of fuel from the core on March 15 eliminated the need per TS to have an operable DG. The Station had not initiated any Limiting Conditions of Operation prior to this date, however, since it was not known as of that time that either DG was inoperable.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION								Form Rev 2.0
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Quad Cities Unit Two	0 5 0 0 0 2 6 5	9 3	-	0 1 2	-	0 0		0 3 OF 0 4

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

On March 25, 1993, the Unit 2 DG was taken Out of Service (OOS) for scheduled outage maintenance. On March 29, an Operator while on his routine rounds questioned the height of the Unit 2 DGCWP oiler. Maintenance examined the bearings for possible damage. Upon removal of the vent cap, metal particles were found in the bearing housing. Upon disassembly of the pump, approximately one tablespoon of oil was found in the oil reservoir. This is the expected oil level based on the height of the oiler. The bearing retainer ring, which provides spacing between the ball bearings, was found in pieces. The races and the ball bearings were intact, but the bearing and pump shaft had apparent heat damage. The balls were coated with a heavy grease like film.

The exact date of failure of the bearings is unknown, however, the Unit 2 DG was last demonstrated operable via 2.5 hour run on February 16 by performing QCOS 6600-1, "Diesel Generator Monthly Load Test". There were also three 15 minute runs of the U-2 DGCWP from February 4 through February 13. The February 4 run was the pump operability surveillance which also obtains Inservice Testing (IST) vibration data. No abnormalities were noted.

C. APPARENT CAUSE OF EVENT:

This report is being submitted in accordance with the requirements of 10CFR50.73(a)(2)(i)(B). The cause of the 1/2 DGCWP being inoperable is described in LER 265/93-10. The Unit 2 DGCWP was inoperable from February 16 to March 15 due to inadequate lubrication. The oiler piping was incorrectly assembled due to inadequate training on how to set and position this type of oiler.

D. SAFETY ANALYSIS OF EVENT:

The safety significance of this event is minimal. The U-2 DGCWP may have been able to function after February 16 but for an unknown length of time. CECo cannot conclusively determine how much longer the pump could have operated with the as-found condition. The pump continued to function with no abnormalities being noted up to the time the pump was taken OOS for routine maintenance. In the opinion of company experts, if the bearing did not have adequate lubrication, the pump would not have operated for longer than a few minutes.

The safety significance of this event is dependent upon the ability to operate the 1/2 DG. Under certain 1/2 DG auto-start situations, the 1/2 DGCWP would have failed to start due to electrical logic design deficiencies. The safety significance associated with the 1/2 DG logic is contained in LER 265/93-10.

Furthermore, the 1/2 DGCWP could have been started by taking the pump control switch to trip and then back to the auto after trip or close position.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION Form Rev 2.0

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					Page (3)		
		Year	////	Sequential Number	////	Revision Number			
Quad Cities Unit Two	0 5 0 0 0 2 6 5	9 3	-	0 1 2	-	0 0	0 4	OF	0 5

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

Operators have been trained to identify a loss of power to a DGCWP and would have responded to the event in adequate time to prevent DG damage. Simulator lesson plans include this scenario. Operators, as a part of training, dispatch personnel to the diesel generator whenever it is autostarted. This dispatch increases the likelihood that the inoperable DGCWP condition would have been promptly corrected. Quad Cities Annunciator Procedure QCAN 901-1(2)-8 A-4 "Diesel Generator 1/2 Trouble", requires the control room operator to dispatch an operator to DG local panel of the trouble alarm. This is the first required operator action.

Operators receive extensive training on the importance of the DGCWP to operability of the DG in a loaded condition.

Quad Cities Annunciator Procedure 2212-45 C-3, "Cooling Water Pump Failure", requires the operator at the local DG panel to manually start the 1/2 DGCWP if the pump is not running. This would be accomplished by first attempting to manually start the pump by placing the control switch to start. If this did not start the pump, further action would have required the operator to move the feed power selector switch to Bus 28, starting the pump.

An Event Tree analysis was performed to describe the operators' actions during this scenario.

The Event Tree analysis indicates that it would be reasonable to conclude that actions necessary to restore power to the 1/2 DGCWP would have been accomplished in 5 to 10 minutes from the event initiation. Therefore, even with problems with a period of indeterminate operability of the Unit 2 DGCWP, it is reasonably likely that the 1/2 DGCWP would have been started in time to prevent a complete loss of onsite power on Unit 2. It is also significant that the probability of a LOCA coincident with a loss of all offsite power is approximately 10 E-08/yr.

E. CORRECTIVE ACTIONS:

The corrective actions associated with the 1/2 DGCWP inoperability is described in LER 265/93-10.

Corrective actions for the improper assembly of the U-2 DGCWP oiler piping include the following. The Unit 2 DGCWP was replaced, and the pump operability surveillance QCOS 6600-6, "Quarterly Diesel Generator Cooling Water Pump Flow Rate Test", was performed and the pump declared operable on April 10, 1993.

The Technical Staff performed walkdowns on safety related and nonsafety related equipment sightglasses and oilers in the plant to ensure proper installation.

The Operations Department held discussions on how to determine proper oil level during operator rounds.

To address the inadequate training of maintenance personnel on oiler piping assembly, a detailed training session was held by the Master Mechanic with the mechanics using the actual DGCWP hardware that was improperly positioned as a mockup and training guide.

LER265\93\012.WPF

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION								Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					Page (3)	
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Quad Cities Unit Two	0 5 0 0 0 2 6 5	9 3	-	0 1 2	-	0 0	0 5 OF 0 5	
TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]								

Operations and Maintenance have jointly conducted plant walkdowns to further clarify the drawings/instruction used by Operations and Maintenance concerning sightglasses and oilers. A matrix has been developed on the different styles of sightglasses and oilers in the plant. An action plan has been developed to address the results of the walkdowns and how they relate to enhanced training, both Operations and Maintenance lesson plan revisions, and the marking of sightglasses. (NTS #2651809301201) will track implementation of the action plan)

A self-assessment was chartered utilizing corporate groups and onsite Quality Verification (QV) to look at craft capability, work package detail and other maintenance practices. Upon receipt of the report from the task force, the Maintenance Superintendent will review the recommendations for applicability and implement an action plan by September 1, 1993. (NTS 2651809301202).

By July 1, 1993 a followup "Lessons Learned Green Border Notification" will be issued to all CECo sites describing this event, its causes, and corrective actions (NTS#2651809301203).

F. <u>PREVIOUS EVENTS:</u>

A search was performed for previous events.

See LER 265/93-010 for previous events involving inadequate design of the diesel generators.

No previous events were identified involving low oil level due to sightglass or oilers being installed improperly.

An NPRDS Search identified 4 previous occurrences in industry involving bearing failures related to incorrectly installed or adjusted oilers.

G. <u>COMPONENT FAILURE DATA:</u>

The U-2 DGCWP was manufactured by Ingersoll Rand [I075], Model 5SB.

LER265\93\012.WPF

LER No. 289/93-002
Three Mile Island Unit 1

NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
THREE MILE ISLAND, UNIT 1	0 5 0 0 0 2 8 9	1 OF 0 6

TITLE (4): BYPASS OF BOTH DECAY HEAT SERVICE COOLERS DUE TO PERSONNEL ERROR

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
5 1	2 9	9 3	9 3	– 0 0 2	– 0 0	0 3	0 5	9 3		0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)	X	50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
M. R. Knight, TMI-1 Licensing Engineer	7 1 7 9 4 8 - 8 5 5 4

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

BYPASS OF BOTH DECAY HEAT SERVICE COOLERS DUE TO PERSONNEL ERROR

TMI-1 was operating at 100% power. On January 29, 1993 during the performance of a weekly procedure, not required by Technical Specifications (TS), the Auxiliary Operator (AO) failed to follow established operator work practices and established a valve lineup which caused river water to bypass both Decay Heat Service Coolers (DC-C-2A/B) simultaneously. When discovered, the proper alignment was immediately restored. The root cause of this event was personnel error.

TS 3.3.1.1.d requires two Decay Heat Removal Coolers (DH-C-1A/B) and their cooling water supplies, including coolers DC-C-2A/B, during plant operation. With both coolers bypassed, TS 3.0.1 was applicable. This condition is reportable under 50.73.a.2.i.B and also under 50.73.a.2.vii.

Bypassing both coolers simultaneously had no immediate safety significance during the event because the equipment was not called upon to be in operation. In the event of a worst case Loss of Coolant Accident, the safety systems would have fulfilled their intended function.

Management has reviewed this event with the affected crew. Procedures will be upgraded. Each Operating crew will review the event.

NRC Form 366 (9-83)

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

BYPASS OF BOTH DECAY HEAT SERVICE COOLERS DUE TO PERSONNEL ERROR

I. Plant Operating Conditions before Event:

TMI-1 was operating at 100% rated power.

II. Status of Structures, Components, or Systems that were Inoperable at the Start of the Event and that Contributed to the Event:

None

III. Event Description:

Operations Surveillance OPS-S227, "DR-P-1A/B Periodic Operation," is a weekly non-Tech Spec surveillance normally performed by the operating shift between 11:00 pm and 7:00 am. The purpose of this surveillance is to assure that each Decay Heat River Water (DR) Pump [BI/P] operates for at least one hour per week to avoid the potential for silt buildup at the pump suction. During the early 1980s, when the facility was in extended shutdown and core decay heat levels were extremely low, OPS-S227 provided guidance for bypassing a Decay Heat Service Cooler (DC-C-2A or DC-C-2B) [BI/CLR] if there was a concern for a thermal transient (extreme cooling) on the Decay Heat Removal (DHR) System or the Decay Heat Closed Cooling Water (DCCW) System. The option to bypass coolers in accordance with OPS-S227 has not been needed since restart in 1985 after the six year shutdown.

During the performance of OPS-S227 on January 29, 1993, the non-licensed Auxiliary Operator (AO) failed to follow established operator work practices and bypassed both DC-C-2A and DC-C-2B simultaneously at about 0100 hours. The DR System was not required to be in operation, so neither DR Pump was operating.

Control Room personnel were unaware that both coolers were bypassed until about 0330 hours when a licensed Control Room Operator (CRO) discovered this condition while attempting to determine the status of preparations for performing OPS-S227. During a later critique of the event, the AO stated that after bypassing both coolers he reported the condition to the Control Room so the surveillance could proceed. However, Control Room personnel do not remember receiving the report. When the CRO discovered that the DR valves (DR-V3A/B, and DR-V5A/B) [BI/V] were not in the required position, he immediately informed the Shift Supervisor who directed the crew to restore and independently verify the required Engineered Safeguards (ES) valve alignment. Realignment of the coolers

NRC Form 366A (6-89)

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

and independent verification were completed by approximately 0355 hours.

DCCW is a closed loop cooling water system which rejects heat to river water (ultimate heat sink) through the Decay Heat Service Coolers (DC-C-2A/B). DCCW cools the Decay Heat Removal System (DHR) Coolers [BP/CLR] and the following safety related pumps:

1. DCCW Pumps bearings [CC/P] (TS 3.3.1.4.c),
2. DHR Pumps motor and bearings [BP/P] (TS 3.3.1.1.c),
3. Reactor Building Spray (BS) Pumps motor and bearings [BE/MO] (TS 3.3.1.3.a), and
4. Makeup Pumps (MU-P1A and C) motor [CB/MO], gear reducer [CB/RGR], and bearings (TS 3.3.1.1.b).[1]

Technical Specification (TS) 3.3.1.1.d requires two DHR Coolers (DH-C-1A/B) [BP/CLR] and their cooling water supplies, which includes the Decay Heat Service Coolers (DC-C-2A/B), during plant operation. One train is allowed to be removed from service for up to 72 hours. With both coolers inoperable (bypassed), TS 3.3.1.1.d was not met. TS 3.0.1 (comparable to STS 3.0.3) was applicable. This condition was reportable under 50.73.a.2.i.B as an event or condition prohibited by the Plant's Technical Specifications, and also under 50.73.a.2.vii as an event where a single cause or condition caused two independent trains to become inoperable in a single system designed to remove residual heat or mitigate the consequences of an accident.

The root cause of this event was personnel error. The AO bypassed both coolers at the same time in violation of established operator work practices. The AO failed to operate the equipment in accordance with Administrative Procedure (AP) 1029, "Conduct of Operations," which would have required authorization from the Shift Supervisor, Shift Foreman, or CRO prior to manipulating the valves. Additionally, operation of both trains of ESAS components was in violation of operator work practices. Further evaluation will determine to what extent communications, work preparation, and work control by the shift personnel contributed to this event.

To a lesser extent, clarity of the procedural guidance also contributed. The instructions in OPS-S227 did not provide guidance for determining if a thermal transient would occur, did not specify that only one cooler at a time should be bypassed and that bypassing a cooler rendered the train out of service and started a TS time clock. However, the instructions in OPS-S227 that contributed to this event could have been eliminated

[1] Makeup Pump MU-P1B is cooled by Nuclear Services Closed Cooling Water (NSCCW) and was unaffected by this event.

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entirely since they are not applicable to an operating station. If the guidance had been contained in the appropriate Operating Procedure, exposure to the biennial review process could have resulted in either enhanced presentation to clarify the use of this option or removed it entirely.

IV. Component Failure Data:

None.

V. Automatic or Manually Initiated Safety System Responses:

No safety system responses were involved in this event.

VI. Assessment of the Safety Consequences and Implications of the Event:

Bypassing both coolers had no immediate safety significance during the event since neither train was called upon to be in operation.

GPU Nuclear has completed calculations which predict the temperature and pressure versus time for the containment during a Large Break Loss Of Coolant Accident (LBLOCA) with DR not available. The analysis was performed using single train availability and other standard FSAR assumptions regarding ambient conditions, core decay heat, Reactor Building (RB) initial conditions and equipment operability. The calculations were performed with Borated Water Storage Tank (BWST) temperature at 120°F, as well as at the actual temperature at the time of the event (70°F). The assumption of single train availability results in a time for switchover from the BWST to sump recirculation of about 72.5 minutes following an accident. Assuming all pumps are operable, the time to switchover would be about 30 minutes (minimum time).

GPU Nuclear has concluded that if a worst case LOCA were to occur with DR isolated, the core and containment response would be unaffected prior to sump recirculation. Following sump recirculation, the core and containment cooling would be continued since sufficient Net Positive Suction Head (NPSH) would be available to the Low Pressure Injection (LPI) and BS pumps and the Reactor Building Emergency Cooling (RBEC) fan coolers [BK/FCU] would remove decay heat from containment. The automatic Control Room a'arm on Main Annunciator Panel C-2-8 [IB/TA] actuates almost immediately after starting RB sump recirculation at a Decay Heat Service Cooler, DCCW outlet temperature of 100°F.

The remaining concern is to provide continuous DCCW cooling to assure long term LPI and BS pump component cooling. The exact time period over which

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APPROVED OMB NO 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530) U.S. NUCLEAR REGULATORY COMMISSION WASHINGTON DC 20555 AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104) OFFICE OF MANAGEMENT AND BUDGET WASHINGTON DC 20503

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

these components would continue to operate without DR flow through the coolers has not been determined by quantitative calculations. GPU Nuclear engineering judgement indicates that at least 30 minutes would be available for operator action to restore the DR valve alignment after receiving the alarm in the Control Room (i.e., at least one hour after the start of the event). If the conservatism of this evaluation was removed, it could be shown that the safety function of DCCW components could be sustained longer, perhaps indefinitely.

On receiving the alarm in the Control Room, the operators are directed to investigate reduced DR system flow and verify the DR System valve lineup. With the installed alarm actuated on DCCW high temperature followed by the individual high bearing temperature alarms on these components, GPU Nuclear concludes that, in accordance with procedure instructions, operator action to reopen the isolation valves would be taken promptly to successfully reestablish full DCCW cooling prior to component degradation.

Based on the above, GPU Nuclear concludes that the safety function of mitigating the consequences of an accident and of removing core decay heat, would have been achieved if a LBLOCA had occurred while the coolers were bypassed.

VII. Previous Events of a Similar Nature:

None.

VIII. Corrective Actions Taken:

The Operations Director has reviewed this incident with the crew involved to ensure that they recognize the errors that were committed and their significance.

IX. Corrective Actions Planned:

1. Administrative Procedure (AP) 1016 will be revised to exclude from the Operations Surveillance Program tasks which operate a system or component outside the envelope of the approved system Operating Procedure.

2. Operations Surveillance Procedures similar to OPS-S227 will be revised to ensure that detailed procedural guidance for evolutions that can potentially affect safe plant operations are removed and placed in approved Operating Procedures. Initial review of the program has identified three surveillances that are similar to

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

OPS-S227. A comprehensive review is in progress and it is expected that only a small number of procedures will be affected. These Operations Surveillance Procedures will reference approved Operating Procedures for proper guidance. This will assure that such activities receive a periodic review through the biennial procedure review process.

3. Each operating crew will review this event to ensure their understanding of the errors that were committed and how similar errors can be avoided. Conformance to the Administrative Procedure guidance on verbal communications, work preparation, and work control will be emphasized.

4. A more comprehensive review of the human performance aspects involved in this event will be conducted to include the roll of supervision, communications, and what improvements in work practices and controls are indicated.

These actions will be completed by May 1993.

* The Energy Industry Identification System (EIIS), System Identification (SI) and Component Function Identification (CFI) Codes are included in brackets, "[SI/CFI]", where applicable, as required by 10 CFR 50.73(b)(2)(ii)(F).

NRC Form 366A (6-89)

LER No. 293/93-004
Pilgrim

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
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LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Pilgrim Nuclear Power Station	05000 293	1 OF 22

TITLE (4): Automatic Scram Resulting From Load Rejection at 100 Percent Reactor Power

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									N/A	05000
03	13	93	93	004	00	4	12	93	N/A	05000

OPERATING MODE (9): N

POWER LEVEL (10): 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)	X	73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)	X	50.73(a)(2)(vii) B		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X	50.73(a)(2)(i) B		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Douglas W. Ellis - Senior Compliance Engineer	(508) 747-8160

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	EA	SWGR	G080	Y					

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO	EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On March 13, 1993, at 1628 hours, an automatic scram resulting from a load rejection occurred during a severe coastal storm while at 100 percent reactor power. The load rejection included a trip of the Turbine-Generator, transfer of station electrical loads, and brief opening of one Main Steam relief valve. The 120 VAC safeguards Buses 'A' and 'B' de-energized. The Reactor Vessel (RV) pressure-temperature (P-T) limit was exceeded during subsequent cooldown.

The load rejection was caused by 345 KV switchyard insulator flashovers due to wind packed snow deposited during blizzard conditions. Corrective actions taken included an inspection of the switchyard and insulators. The cause of exceeding the P-T limit was a RV pressure increase that occurred after the HPCI System, that was being used for RV pressure control, was removed from service due to high Suppression Pool water level. The P-T condition was evaluated. The evaluation concluded the RV did not exceed the allowable limits of ASME sections III and XI. The cause of the de-energized safeguards buses was trip settings that were too low. The trip settings were subsequently increased. Other corrective or preventive actions were taken or are planned. The unit returned to commercial service at 0459 hours on March 17, 1993.

This event occurred near the end of the fuel cycle during power operation with the reactor mode selector switch in the RUN position. The RV pressure was 1025 psig with RV water temperature at 525 degrees Fahrenheit.

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NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
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Pilgrim Nuclear Power Station	05000 293	93	- 004 -	00	2 OF 22

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

BACKGROUND

A period of sustained easterly onshore winds began on March 12, 1993, and continued through March 15, 1993. The winds were due to a severe coastal storm. The winds were accompanied by snow until the early evening on March 13, 1993, when a change to sleet, later followed by a change to heavy rains, occurred. Snow accumulations quickly increased with distance from the coast. Intermittent electrical power outages occurred in some offsite transmission systems and offsite emergency conditions were declared by Commonwealth of Massachusetts officials due to some coastal flooding and snow-related effects of the storm.

Seaweed was transported to the Intake Structure as a result of the winds and unusually high tides. Operation of the traveling screens that are part of the Circulating Water System was necessary because of the seaweed.

Just prior to the event, plant operating conditions included the following. The reactor mode selector switch was in the RUN position. The reactor was at 100 percent power and near the end of the fuel cycle. The Reactor Vessel (RV) pressure was 1025 psig with the RV water temperature at approximately 525 degrees Fahrenheit. The RV water level was approximately +27 inches.

The Recirculation System motor-generator sets/pumps 'A' and 'B' were in service with each loop in the local manual control mode. Reactor core flow was approximately 70 million pounds per hour. The Condensate System and Feedwater System pumps were all in service. The Feedwater Level Control System was in the three element control mode. The Salt Service Water (SSW) System Loops 'A' and 'B' were in service with one pump operating in each loop. The Reactor Building Closed Cooling Water (RBCCW) System Loops 'A' and 'B' were in service with one pump operating in each loop.

The 345 KV transmission lines 342 and 355 were in service. The Startup Transformer (SUT) was in standby service with ACBs 102 and 103 closed. The 345 KV switchyard ring bus was energized with ACBs 104 and 105 closed. The Emergency Diesel Generators (EDGs) 'A' and 'B' were in standby service. The 4160 VAC Auxiliary Power Distribution System (APDS) was energized from the Unit Auxiliary Transformer (UAT). The Shutdown Transformer was in standby service with the 23 KV distribution system energized. Located at the end of this report is a figure depicting a simplified, single line diagram of the switchyard, including the ACBs and 345 KV transmission lines.

The Main Turbine auxiliary oil pumps 'A' and 'B' were in standby service.

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Pilgrim Nuclear Power Station	05000 293	93	- 004 -	00	3 OF 22

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

EVENT DESCRIPTION

On March 13, 1993, at 1628 hours, an automatic Reactor Protection System (RPS) scram signal and scram occurred while at 100 percent reactor power. The scram signal occurred as a result of a load rejection. The event was initiated when ACBs 104 and 105 automatically opened, thereby isolating the Main Transformer from the switchyard. The opening of ACBs 104 and 105 resulted in an automatic trip signal to the 4160 VAC Buses and Generator load rejection.

The source of 4160 VAC power for the APDS automatically fast-transferred from the UAT to the SUT. Except for nonsafety-related 4160 VAC Bus A3, the transfer occurred as designed. Nonsafety-related Bus A3 became de-energized because switchgear breaker 152-303, that was closed and powering Bus A3 from the UAT at the time of the event, opened automatically for the transfer but switchgear breaker 152-304, that feeds Bus A3 from the SUT, did not close. The de-energization of Bus A3 resulted in the following designed responses:

- The drive motor of the Recirculation System Loop 'A' motor-generator (MG) set de-energized. Meanwhile, the Loop 'B' MG set/pump automatically ran back to minimum flow and continued forced circulation in the RV.
- The motor of the Circulating Water System Train 'A' pump de-energized.
- The 480 VAC Bus B3 and related loads including RPS Bus 'A' de-energized.
- The loss of power to the circuit breaker that powers the motor of the Main Turbine auxiliary oil pump 'A'.

The Generator load rejection resulted in the opening of the Generator field breaker, acceleration of the Turbine-Generator, and trip of the acceleration relay. The trip included the following responses:

- Loss of oil pressure to pressure switches (PS-37/38/39/40) that resulted in the RPS scram signal (control valve fast closure due to load reject).
- Automatic closing of the Turbine Stop Valves and Combined Intermediate Valves, and the trip of the Turbine lockout relay (286-2).
- Automatic closing of the four Turbine Control Valves.
- The three hydraulically-operated Turbine Bypass Valves gradually closed because the Main Turbine shaft driven oil pump pressure gradually decreased and the Turbine auxiliary oil pump 'A' could not start. Pump 'B' did not start because of its interlock with pump 'A'.

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

The Main Steam/RV pressure increased because the Turbine Bypass Valves were closed. The pressure increase caused the Target Rock two-stage Main Steam relief valve RV-203-3A (pilot s/n 1049) to briefly lift for pressure relief.

The 120 VAC safeguards Bus 'A' Panel Y3/31 and Bus 'B' Panel Y4/41 became de-energized during the event. The loss of power from Panels Y3 and Y4 resulted in the de-energization of related equipment including some normally energized relays that are part of the Primary Containment Isolation Control System (PCIS) and Reactor Building Isolation Control System (RBIS).

Meanwhile, the RV water level decreased in response to the scram and RV pressure increase that resulted in a decrease in the void fraction in the RV water. The RV water level eventually decreased to approximately -20 inches. The decrease in RV water level to less than the low RV water level setpoint (calibrated at approximately +12 inches) resulted in trip signals to the portions of the PCIS and RBIS that had already actuated. EOP-01 (Rev. 1), "RPV Control", was entered because the RV water level was less than +9 inches.

The PCIS actuation resulted in the following designed responses:

- Automatic closing of the inboard and outboard Primary Containment System (PCS)/Reactor Water Sample isolation valves AO-220-44 and -45.

- Automatic closing of the inboard and outboard PCS Group 2 (two) isolation valves that were open.

- The PCS Group 3/Residual Heat Removal (RHR) System Shutdown Cooling suction piping isolation valves MO-1001-47 and -50 remained closed.

- The PCS Group 3/RHR System Low Pressure Coolant Injection mode valves MO-1001-29A/B remained closed.

- The PCS Group 6 (six)/Reactor Water Cleanup (RWCU) System isolation valves closed automatically.

The RBIS actuation resulted in the automatic closing of the Reactor Building/Secondary Containment System (SCS) Trains 'A' and 'B' supply and exhaust ventilation dampers and automatic start of the SCS/Standby Gas Treatment System (SGTS) Trains 'A' and 'B'.

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Initial Control Room operator response was orderly and included the following. The reactor mode selector switch was moved to the SHUTDOWN position in accordance with procedure 2.1.6, "Reactor Scram". The insertion of the control rods was verified. Indications of the de-energizing of Bus A3 and Panels Y3 and Y4 were noted.

At 1635 hours, the High Pressure Coolant Injection (HPCI) System was put into service in the flow test mode for RV pressure control. This action was taken in accordance with EOP-01 because the Turbine Bypass Valves, that would normally operate to provide a pathway from the Main Steam piping to the Main Condenser, were closed. At 1637 hours, an RHR System Loop 'A' pump was put into service in the Suppression Pool Cooling (SPC) mode because of the expected addition of heat from the HPCI turbine exhaust steam.

At 1640 hours, ACB 102 opened automatically and the 345 KV transmission line 355 de-energized. The opening of ACB 102 removed line 355 as a source of power to the SUT.

At 1650 hours, Bus A3 was re-energized from the SUT via switchgear breaker 152-304. The Turbine auxiliary oil pump 'A' was started after Bus A3 was re-energized. The start of pump 'A' provided hydraulic oil pressure to the Turbine Bypass Valves. The Turbine Bypass Valves re-opened and provided a steam path to the Main Condenser.

At 1654 hours, the HPCI System was returned to standby service because the Turbine Bypass Valves were controlling RV/Main Steam pressure.

At 1655 hours, the Emergency Diesel Generators (EDGs) 'A' and 'B' were manually started and loaded onto 4160 VAC Emergency Buses A5 and A6, respectively. This precautionary action was taken in accordance with procedure 2.4.144, "Degraded Voltage". A potential transformer (PT) fuse failure alarm occurred while starting EDG 'B'. The alarm was not caused by a PT fuse failure and the loading of EDG 'B' was not affected. Subsequent investigation revealed the alarm was caused by the EDG 'B' voltage balance relay 160-609 auxiliary relay 'XA'.

At 1656 hours, Panels Y4/Y41 were re-energized in accordance with procedure 5.3.19 (Rev. 9), "Loss of 120 VAC Safeguards Buses Y4 and Y41". Panels Y3/Y31 were re-energized in accordance with procedure 5.3.18 (Rev. 9), "Loss of 120 VAC Safeguards Buses Y3 and Y31", at 1657 hours.

At 1700 hours, RPS Bus 'A' was re-energized via the standby RPS transformer that was powered from Bus A5 via 480 VAC Buses B1/B6 and MCC-B10. This precautionary action was taken to preclude the closing of the Main Steam Isolation Valves (MSIVs) if RPS Buses 'A' and 'B' were to become de-energized.

At 1705 hours, the RPS was reset.

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At 1710 hours, ACB 103 opened automatically and 345 KV transmission line 342 de-energized. The opening of ACB 103 removed line 342 as a source of offsite power to the SUT. The opening of ACB 103 in conjunction with the previous opening of ACB 102, resulted in the loss of power to the SUT. The nonsafety-related 4160 VAC Buses A1, A2, A3, and A4 became de-energized as a result of the loss of power to the SUT. Emergency 4160 VAC Buses A5 and A6 and related loads remained energized via EDGs 'A' and 'B'. The loss of power to Bus A1 and A2 de-energized the motors of the Condensate and Feedwater Systems pumps and resulted in a loss of feedwater flow to the RV. The loss of power to Bus A3 and A4 de-energized equipment including:

- The motors of the Turbine auxiliary oil pumps. This resulted in the loss of oil pressure to and closing of the Turbine Bypass Valves.

- The drive motors of the Recirculation System loop 'A' and 'B' motor-generator sets. This resulted in the loss of Recirculation System Loop 'B' flow and, in conjunction with the previous loss of Loop 'A' flow, resulted in the loss of forced circulation in the RV.

- The motors of the Circulating Water System Train 'A' and 'B' pumps. This resulted in a loss of seawater flow to the Main Condenser and the heat sink function of the Main Condenser.

- 480 VAC Buses B3 and B4 and related electrical loads including RPS Bus 'B'. RPS Bus 'A' remained energized via the standby RPS transformer. The MSIVs remained open as designed.

At 1711 hours, the Reactor Core Isolation Cooling (RCIC) System was put into service in the injection mode for RV water level control. At 1712 hours, the HPCI System was put into service in the flow test mode for RV pressure control because the Turbine Bypass Valves were closed. These actions were in accordance with EOP-01.

At 1715 hours, the RV pressure and water temperature began to decrease because of the continued removal of steam via HPCI turbine and RCIC turbine operation. Procedure 2.1.7 (Rev. 27), "RPV Temperature and Pressure Checklist", was initiated.

At 1730 hours, the MSIVs were closed in accordance with procedure 2.4.49 for a loss of condensate flow. The outboard Main Steam line 'B' MSIV AO-203-2B exhibited a dual position indication (open/closed). The in-series MSIV AO-203-1B was tagged closed in accordance with Technical Specification 3.7.A.2.b. Followup investigation revealed the valve was closed. The indicated position was due to a limit switch that was later aligned.

At 1739 hours, an RHR System Loop 'B' pump was put into service in the SPC mode for increased Suppression Pool cooling.

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At 1742 hours, EOP-03 (Rev. 1), "Primary Containment Control", was entered because the Suppression Pool temperature was greater than 80 degrees Fahrenheit. The temperature ultimately reached 95 degrees Fahrenheit.

At 1755 hours, procedure 2.1.5 (Rev. 41) Section E, "Maneuvering to Cold Shutdown with MSIVs Closed", was entered.

At 1815 hours, the Post Accident Sampling System Hydrogen-Oxygen Trains 'A' and 'B' were put into service in accordance with EOP-03.

At 2005 hours, the SGTS Train 'A' was put into service to reduce Torus atmosphere pressure and maintain the Drywell-to-Torus atmosphere differential pressure. Train 'A' was returned to standby service at 2112 hours.

At 2155 hours, 345 KV line 342 was re-energized and ACB 103 was reclosed in accordance with regional power authority (REMVEC) direction. The closing of ACB 103 re-energized the SUT.

At 2208 hours, Bus A3 was re-energized from the SUT and Bus A4 was subsequently re-energized from the SUT. The Turbine auxiliary oil pumps 'A' and 'B' were started at 2212 hours.

At 2227 hours, the RPS Bus 'B' motor-generator set was started and related circuitry including RPS Channel 'B' was re-energized. The source of power for RPS Bus 'A' was transferred from MCC-B10 to the RPS Bus 'A' motor-generator set at 2233 hours.

At 2235 hours, 345KV ACB 104 was closed per REMVEC direction.

At 2237 hours, the RCIC System was returned to standby service.

At 2244 hours, the RPS was reset.

At 2255 hours, 345KV ACB 105 was closed per REMVEC direction.

At 2300 hours, the HPCI System, in the full flow test mode for RV pressure control, was returned to standby service. This action was taken because the HPCI pump supply valves MO-2301-35 and -36 in the suction piping from the Suppression Pool opened. The valves opened because the Suppression Pool level had increased to approximately +3.5 inches. As a result of the opening of the valves, the HPCI pump supply valve MO-2301-6 in the suction piping from the Condensate Storage System closed and the HPCI test valves MO-2301-10 and -15 closed. The closing of valves MO-2301-10/-15 eliminated the use of the HPCI System in the flow test mode for RV pressure control. The HPCI System injection function was not affected.

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The RV pressure began to increase approximately 10 psi per minute because the RV was isolated.

By 2303 hours, activities were completed to return the Radwaste System to service. The letdown of Suppression Pool inventory to the Radwaste System was initiated via the RHR System SPC mode.

At 2320 hours, the RV pressure was 510 psig while the RV bottom head metal temperature was 110 degrees Fahrenheit. This condition was later identified as having exceeded the Technical Specification Figure 3.6.2 pressure-temperature limit. The condition was identified on March 19, 1993.

At 2326 hours, Buses A1 and A2 were re-energized and the RWCU System put into service for RV water rejection to the Main Condenser.

At 2330 hours, the RV water level was approximately +48 inches. The level was greater than the high RV water level trip settings of the HPCI System, and RCIC System, and PCIS Group 1 (MSIVs). Consequently, the RCIC and HPCI Systems were not available for service and the MSIVs could not be opened.

At 2336 hours, an automatic RPS scram signal occurred when the RV pressure reached the scram setpoint (calibrated at approximately 572 psig) while the MSIVs were closed.

At 2338 hours, the Group 6/RWCU isolation valve MO-1201-2 closed automatically. This nonsafety-related isolation occurred because of a sensed high water temperature at the outlet of the RWCU System non-regenerative heat exchanger.

By 2344 hours, the Suppression Pool water level had been lowered sufficiently to allow the use of the HPCI/RCIC System for RV pressure control.

At 2355 hours, the Group 6 portion of the PCIS was reset and the RWCU System was put into service for RV water rejection to the Main Condenser.

At 2348 hours, the Condensate System pump 'C' was started as part of preparations for returning the Main Condenser to service as a heat sink.

On March 14, 1993, at approximately 0015 hours, the shift Nuclear Watch Engineer and Chief Operating Engineer discussed the use of the Main Steam relief valves to resume the RV cooldown and lower the RV water level. This use of the relief valves is allowed by EOP-01. The relief valves were not used at that time because of the following considerations:

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- The RV heatup rate was controlled.
- RWCU System letdown operation might reduce the RV water level to less than +48 inches prior to exceeding the high RV pressure scram setpoint and EOP-01 pressure limit of 1085 psig, thereby precluding the use of the relief valves.
- The RV pressure had stabilized at approximately 660 psig. The opening of a relief valve could possibly result in a rapid RV depressurization cooldown.

Consequently, the decision was made to monitor RV pressure and level, and determine if HPCI/RCIC System operation and/or the opening of the MSIVs could reduce RV pressure/water level and thereby preclude the opening of a relief valve. The RV water level and pressure were monitored. By 0050 hours, monitoring indicated that RWCU letdown operation was not sufficient to preclude the use of the relief valves and the RV pressure had gradually increased to approximately 820 psig.

At approximately 0100 hours, the Main Steam relief valves RV-203-3B/C/D/A were individually opened to reduce RV pressure and RV water level in accordance with EOP-01. The last relief valve was reclosed at approximately 0105 hours. This reduced the RV pressure to approximately 650 psig and reduced the RV water level to less than the high RV water level trip settings of the HPCI and RCIC Systems, and the high RV water level isolation trip setting of the MSIVs.

At 0111 hours, the Group 2 portion of the PCIS and the RBIS were reset. The SGTS was returned to standby service and the Reactor Building ventilation system was returned to service. Meanwhile, the Main Steam relief valve RV-203-3B was opened and RV pressure (then 700 psig) decreased to approximately 600 psig.

At 0121 hours, the HPCI System was put into service for RV pressure control. The RCIC System was put into service for RV water level control.

By 0140 hours, the RV pressure was 450 psig and the HPCI System was returned to standby service.

At 0202 hours, the RCIC turbine barometric condenser condensate pump P-221 overload alarm occurred while the RCIC System was in the flow test mode for RV pressure control. Actions taken were in accordance with alarm response procedure ARP-904L and RCIC System procedure 2.2.22. The alarm did not affect the operability of the RCIC System.

At 0205 hours, the HPCI System was put into service for RV pressure control.

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At 0236 hours, the RCIC System was put into service for RV water level control and was returned to standby service at 0242 hours.

At 0245 hours, the RV P-T limit was no longer exceeded because the RV pressure was 320 psig with the RV bottom head temperature at 92 degrees Fahrenheit.

At 0300 hours, the RWCU System was removed from service. At 0305 hours, the SGTS Train 'B' was put into service and Train 'A' was subsequently put into service. The actions were taken as part of preparations for the subsequent transfer of power supplies.

At 0320 hours, 480 VAC transfer Bus B6 was transferred from Bus B1 to Bus B2. The source of power to Bus A5, which is the source of power to Bus B1, was transferred from EDG 'A' to the SUT at 0322 hours. EDG 'A' was returned to standby service at 0331 hours and Bus B6 was transferred from Bus B2 to Bus B1. The source of power to Bus A6, which is the source of power to Bus B2, was transferred from EDG 'B' to the SUT at 0345 hours. EDG 'B' was returned to standby service at 0357 hours.

At 0404 hours, the RPS was reset.

At 0415 hours, the SGTS Trains 'A' and 'B' were returned to standby service.

At 0430 hours, the Post Accident Sampling System/Hydrogen-Oxygen System was put into service in accordance with EOP-03.

At 0448 hours, the MSIVs in the Main Steam lines 'A', 'C', and 'D' were opened.

At 0522 hours, the RWCU System was put into service.

At 0857 hours, EOP-01 and EOP-03 were exited and the Hydrogen-Oxygen System was returned to standby service.

At 0858 hours, the RHR System was secured from the SPC mode of operation and returned to standby service.

At 0905 hours, the SGTS Train 'B' was put into service to reduce the Torus atmosphere pressure and was returned to standby service at 1030 hours.

At 1035 hours, an RHR Loop 'B' pump was started in the SPC mode to reduce the Suppression Pool level and was returned to standby service at 1050 hours.

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At 1051 hours, a sensed high RWCU System flow condition resulted in a PCIS Group 6/RWCU System isolation. The isolation occurred while adjusting the position of the RWCU valve MO-1201-85 to increase the flow from the RV bottom head drain piping. The event is separately reported in LER 93-005-00. The PCIS Group 6 circuitry was reset and the RWCU System was returned to service at 1100 hours.

At 1444 hours, the RHR Loop 'A' was started in the Shutdown Cooling (SDC) mode with one pump in service.

Cold shutdown was achieved on March 14, 1993, at approximately 1522 hours, when the RV water temperature was less than 212 degrees Fahrenheit. The RV head vent valves were subsequently opened at 1530 hours.

Problem Report (PR) 93.9082 was written to document the event. The NRC Operations Center was notified in accordance with 10 CFR 50.72 at 1900 hours on March 13, 1993.

PR 93.9083 was written regarding the Bus A3 transfer problem. PR 93.9084 was written regarding the de-energization of Panels Y3 and Y4. PR 93.9086 was written regarding the position indication of MSIV AO-203-2B. PR 93.9089 was written regarding the EDG 'B' fuse alarm. Other problem reports were written to document other observations or occurrences related to the shut down.

A post trip review of the event was initiated in accordance with procedure 1.3.37, "Post Trip Reviews".

On March 19, 1993, the RV P-T relationship was identified as having exceeded Technical Specification Figure 3.6.2 during the March 13-14, 1993 cooldown. PR 93.9098 was written to document the discovery.

A followup notification to the NRC Operations Center was made at 1341 hours on March 29, 1993, to update the March 13, 1993, notification regarding the loss of power from Panels Y3 and Y4.

CAUSE

The cause of the load rejection at 1628 hours was the environmental effects of the storm (wind driven snow packing against the 345 KV switchyard insulators). A storm-induced fault on ACB 105 phase 'C' resulted in the automatic opening of ACBs 104 and 105 and consequent load rejection.

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The opening of ACB 102 and line 355 de-energization at 1640 hours was due to a flashover on the energized side of ACB 105. The flashover initiated the Line 355 Primary Ground Fault Detection Relay 67N and ACB 105 Column Fault Overcurrent Relay 64/5. Relay 67N initiated the opening of ACB 102. Relay 64/5 initiated the ACB 105 lockout relay 86/5 which initiated a trip signal to ACB 102 and a transfer trip signal to switching devices at the remote end of line 355. These protective relay operations caused the opening of ACB 102 and de-energization of line 355.

The opening of ACB 103 at 1710 hours was due to a flashover on the energized side of ACB 102. The flashover initiated the ACB 102 Column Fault Overcurrent Relay 64/2. Relay 64/2 operation initiated the ACB 102 lockout relay 86/2 that initiated a trip signal to ACB 103 and transfer trip signal to switching devices at the remote end of line 342. These protective relay operations caused the opening of ACB 103 and de-energization of line 342 and, together with the previous operation of protective relays that opened ACB 102, resulted in the loss of power to the SUT. At the approximate same time of the opening of ACB 103, the ACB 103 stuck breaker circuit operated that initiated the operation of the ACB 103 lockout relay 86/3. The affect of the ACB 103 stuck breaker circuit operation was negligible because ACBs 102, 103, 104, and 105 were open.

The cause of the loss of power to Bus A3 could not be determined with certainty. Bus A3 is designed to transfer to the SUT. The Bus A3 fast transfer function was enabled at the time of the event. The switchgear breaker 152-303 contact 52BB, that is part of the circuitry that provides a permissive function to close breaker 152-304, was found to be misaligned. The 52BB contact is connected in parallel with contact 52B. Therefore, even with the misalignment of contact 52BB, breaker 152-304 should have closed automatically after breaker 152-303 opened. Contact 52BB was adjusted and no other circuitry problem was found during troubleshooting. Breaker 152-303 was manufactured by the General Electric Company, type AM-4.16-250-8H, serial number 0209A2839-016.

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

The cause of Panels Y3/31 and Y4/41 becoming de-energized was the trip of the main input breakers of the voltage regulating transformers X-55 and X-56, respectively. The transformers with the main input breakers, that are inside the transformers' cabinets, were installed during the last mid-cycle outage (MCO 92) via PDC 91-59A. The previously installed fixed-tap transformers were not regulating type transformers and did not have an internal input circuit breaker. The trip of the input circuit breakers was caused by low instantaneous trip settings. The as-found nominal settings of the breakers was '2' (900 amperes) and '3' (1000 amperes), respectively. The trip settings were set at '5' (1200 amperes) and tested at the supplier's facility in accordance with the approved dedication plan test instructions. Supplier test documents indicate the settings were left at '5'. The receipt inspection of X55 and X56 included documentation, physical damage, identification and/or marking, protective covers and seals, cleanliness and electrical tests. The receipt inspection did not include a requirement to check or verify the trip settings. After installation, X55 and X56 were pre-operationally tested (TP 92-58). The testing included voltage regulation, input breaker contact resistance, current leakage, initial startup and energization, transformer ratio, relay and alarm functional tests. The testing did not include a requirement to check or verify the trip settings since there were no installation or testing activities that would have caused the settings to be changed. The root cause analysis concluded the most likely cause of the low trip settings was an unauthorized change to the trip settings. The root cause analysis could not determine when the change occurred. Based on root cause analysis findings and review of Pilgrim Station corrective action program documents and LERs, the unauthorized change is believed to be an isolated occurrence. Transformers X55 and X56 were manufactured by Rapid Power Technologies, Incorporated (model number PWTAB015120E). The transformers were supplied by EcoTech/RAM-Q, numbers E/R-2163-15-1 (X55) and E/R-2163-15-2 (X56).

The cause of not conducting an engineering evaluation of the RV P-T condition prior to the subsequent startup was that the condition was not identified until after the startup.

The cause of not identifying the RV P-T condition during the post trip review had not been identified with certainty when this report was prepared. When this report was prepared, the focus of the root cause analysis was the post trip review procedure 1.3.37 that did not require a comparison of the RV P-T relationship during cooldown to the P-T limit.

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CORRECTIVE ACTION

After the storm winds and rain subsided, the switchyard was walked down for evidence of flashover. Evidence of arcing was found at an ACB 102 phase 'A' current transformer bushing and at an ACB 105 stack #1 (Phase 'C') insulator. No cleaning or other corrective actions were necessary as a result of the findings. A washdown of switchyard insulators was not necessary because of the heavy rains that followed the snow and sleet.

The trip settings of the main input circuit breakers for voltage regulating transformers X55 and X56 were increased. The change was implemented via FRN 93-02-03 on March 15, 1993. The new trip settings include additional margin and will preclude a recurrence. The original design trip setting ('5') was sufficient to prevent an unnecessary trip of the input breakers.

The unit returned to commercial service at 0459 hours on March 17, 1993.

Visual inspections of selected electrical equipment will be conducted. The purpose of the inspections is to provide additional assurance that the unauthorized change of the trip settings was an isolated occurrence. This report will be supplemented if significant corrective action is necessary as a result of the inspections.

Previous scram reports have been reviewed. The review focused on events involving RV pressurization with no forced circulation. The review identified no previous event or condition involving a pressurization with no forced circulation in the RV.

Operations Section procedures 2.1.7 (currently Rev 27) and 2.4.24 (currently Rev. 8), "Reactor Vessel Cold Water Stratification", are being evaluated for improvement. The focus of the evaluation is to provide additional operator guidance to preclude a recurrence of exceeding a RV pressure-temperature limit. Procedure 1.3.37 (currently Rev. 27) will be revised. The focus of the revision is to specify a check of transitory parameters governed by applicable Technical Specifications.

PREVENTIVE ACTION

A switchyard events recorder to monitor voltages, currents, and ACB positions will be installed. The recorder will aid in troubleshooting if a switchyard event occurs in the future. This action was previously identified and is being tracked via LER 92-016-00. This is the third plant trip caused by flashover since the insulators were treated with a Sylgard coating in the Summer of 1987. An evaluation of switchyard performance was previously identified and is being tracked via LER 92-016-00.

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Appropriate nuclear organization personnel have been made aware of the root cause of the trip of the input circuit breakers that de-energized Panels Y3/31 and Y4/41. In addition, to heighten the awareness of personnel to the potential for mis-adjustment of adjustable trip settings, engineering personnel have been reminded to include in-process verification of adjustable trip settings, when appropriate.

SAFETY CONSEQUENCES

The events and RV P-T condition posed no threat to public health and safety.

The load rejection with subsequent loss of bypass experienced during this event is bounded by the transient analysis described in the Updated Final Safety Analysis Report section 14.4.3, "Generator Load Rejection Without Bypass". The opening of some or all of the Main Steam two-stage relief valves is an expected response to a load rejection with bypass at greater than 45 percent power. For this event, relief valve RV-203-3A (pilot s/n 1049) opened. The other relief valves RV-203-3B (pilot s/n 1040)/-3C (pilot s/n 1025)/-3D (pilot s/n 1207) did not lift because RV-203-3A lifted and reduced the RV/Main Steam pressure before the pressure could increase to the setpoint of the other valves.

The Technical Specification 3.6.D.1 setting for the Main Steam System/Pressure Relief System (PRS) relief valves is 1095 to 1115 psig with a tolerance of +/- 11 psi. The setpoint of the relief valves is 1115 psig. Therefore, the setpoint range of the relief valves including tolerance is 1104 psig to 1126 psig. During the event, the highest RV/Main Steam System pressure that occurred was approximately 1118 psig.

The Technical Specification 3.6.D.1 setting for the Main Steam/PRS safety valves is 1240 +/- 13 psi. During the event, the highest RV pressure that occurred was approximately 122 psig less than the safety valves' setpoint of 1240 psig.

The scram signal was the designed response to a load rejection with the Turbine first stage pressure at approximately 735 psig which is greater than the scram bypass setpoint (calibrated at 108 psig +/- 3 psig) corresponding to 25 percent of the normal first stage pressure. The maximum turbine speed that occurred was approximately 1863 RPM and was less than the speed corresponding to the emergency trip setting of approximately 1980 RPM.

The decrease in the RV water level was the expected response to the scram and accompanying shrink in the RV water. The PCIS and RBIS actuations were initiated by the de-energization of normally energized relays powered from Panels Y3 and Y4. The actuations are also the expected designed responses to a low RV water level condition (i.e., less than +12 inches).

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The Technical Specification 2.1.I limiting safety system setting for actuation of the Core Standby Cooling Systems (CSCS) is -49 inches. During the event, the lowest RV water level that occurred (-20 inches) was approximately 26 inches above the CSCS setpoint. In addition, the level was approximately 107.5 inches above the level that corresponds to the top of the active fuel zone.

The CSCS consists of the HPCI System, Automatic Depressurization System (ADS), Core Spray System, and RHR/LPCI mode. Although not part of the CSCS, the RCIC System is capable of providing water to the RV for high pressure core cooling, similar to the HPCI System. The ADS is a backup to the HPCI System and functions to reduce RV pressure to enable low pressure core cooling provided independently by the Core Spray System and the RHR/LPCI mode. The CSCS and RCIC System were operable.

The RCIC overload alarm that occurred while the RCIC System was in service did not affect the operability of the RCIC System. The device that senses an overload condition provides an alarm function only and does not provide a trip function to pump P-221.

The lowest RV water level that occurred was greater than the setpoint (calibrated at approximately -46 inches) that initiates the ATWS System functions for a Recirculation Pump Trip (RPT) and Alternate Rod Insertion (ARI). The highest RV pressure that occurred was less than the setpoint (calibrated at approximately 1175 psig) that initiates the ATWS System RPT and ARI trip functions and the setpoint (calibrated at approximately 1400 psig) that initiates the ATWS System function for a Feedpump Trip.

The highest RV water level that occurred was approximately +65 inches. The level was less than the level (approximately 112 inches) corresponding to the bottom of the Main Steam piping.

The highest Suppression Pool bulk water temperature that occurred was approximately 95 degrees Fahrenheit. The temperature was less than the maximum water temperature (120 degrees Fahrenheit) specified by Technical Specification 3.7.A.1.h during RV isolation conditions.

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Technical Specification 3.7.A.1.m specifies the Suppression Pool/Chamber be maintained between -6 to -3 inches which corresponds to a downcomer submergence of 3.00 and 3.25 feet, respectively. The highest Suppression Pool water level that occurred was approximately +3.5 inches (136.5 inches on LI/LR-1001-604A/B). The level was less than the level corresponding to the maximum Suppression Pool volume of 94,000 cubic feet specified by Technical Specification 3.7.A.1.b. A Suppression Pool volume of 94,200 cubic feet corresponds to a level of +6 inches (LR-503B/5049) or 139 inches (LI-1001-604A/B). The level was equal to the settings of level switches LS-2351A/B that control the Suppression Pool/HPCI pump suction valves. The automatic transfer of the HPCI pump suction from the Condensate Storage System to the Suppression Pool occurred as designed.

The safeguards Panels Y3/31 and Y4/41 were de-energized for approximately 28 minutes. The source of power to Panel Y3/31 is Bus A5 via load center Bus B1 and MCC-B17. The source of power to Y4/41 is Bus A6 via load center Bus B2 and MCC-B18. The source of power to Buses A5 and A6 consist of the UAT (during power operation), the SUT, EDG 'A' (Bus A5) and 'B' (Bus A6), the Shutdown Transformer, or Station Blackout Diesel Generator (Bus A5 or A6). The Pilgrim Station electrical design includes the re-energization of Bus A5/A6 within approximately 13 seconds if a loss of offsite power and a design basis loss of coolant accident occurs. During the extra period of time Panels Y3 and Y4 were de-energized, the SSW System Loop 'A' and 'B' pumps and RBCCW System Loop 'A' and 'B' pumps would not have been capable of automatically starting as assumed in the design. The manual start function of the pumps was not affected while the panels were de-energized. The significance of the simultaneous tripping of the input breakers to transformers X55 and X56 was assessed. The assessment concluded the loss of power to Panels Y3/31 and/or Y4/41 is detectable, the actions to re-energize the panels is proceduralized, immediate safety functions are not adversely affected, and the Panels Y3/31 and/or Y4/41 can be repowered in sufficient time to support longer term safety functions.

Technical Specification Figure 3.6.2 identifies the RV P-T limits for subcritical heatup and cooldown. The P-T limit was exceeded during the cooldown on March 13-14, 1993. The effects of exceeding the limit was evaluated. The evaluation concluded the RV did not exceed ASME section III structural limits nor did the RV exceed ASME section XI fracture toughness limits.

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Technical Specification 3.6.A.1 specifies the thermal and pressurization limit shall not exceed 100 degrees Fahrenheit per hour when averaged over a one hour period except when the RV temperatures are above 450 degrees Fahrenheit. The limit was neither exceeded when the temperature was greater than nor was it exceeded when the temperature was less than 450 degrees Fahrenheit. Moreover, the specification also specifies the RV flange to adjacent RV shell temperature differential shall not exceed 145 degrees Fahrenheit. The limit was not exceeded.

This report is submitted in accordance with 10 CFR 50.73(a)(2)(iv) because the actuation of the RPS, although an expected designed response to the load rejection at 100 percent reactor power, was not planned. This report is also submitted in accordance with subpart (a)(2)(iv) because the PCIS and RBIS actuation, although a designed response to the de-energizing of relays energized from Panels Y3 and Y4, was not planned.

This report is submitted in accordance with 10 CFR 50.73(a)(2)(i)(B) because an engineering evaluation for exceeding the RV P-T limits was not conducted prior to the subsequent plant startup.

This report is submitted in accordance with 10 CFR 50.73(a)(2)(ii)(B) because the de-energization of safeguards buses 'A' and 'B' for greater than approximately 13 seconds is a condition that is outside the Pilgrim Station design bases. This report is also submitted in accordance with subpart (a)(2)(vii)(B) because the de-energization of 120 VAC safeguards Panels Y3 and Y4 affected the automatic pump start function of Loops 'A' and 'B' of the SSW and RBCCW Systems.

SIMILARITY TO PREVIOUS EVENTS

A review was conducted of Pilgrim Station Licensee Event Reports (LERs) submitted since January 1984. The review focused on LERs submitted in accordance with 10 CFR 50.73(a)(2)(iv) that involved a load rejection or similar scram. The review identified similar events reported in LERs 50-293/85-025-00, 90-008-00, 91-024-00, and 92-016-00.

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For LER 85-025-00, an automatic scram occurred on September 1, 1985, at 0521 hours, while at 32 percent reactor power. At the time of the event, the Main Condenser was being backwashed and a live washdown of the 345 KV switchyard insulators was being performed to reduce arcing due to salt from a coastal storm. A 345 KV phase 'B' insulator, located on the Main Transformer side of ACB 104, disintegrated and resulted in a load rejection. The scram was caused by high RV pressure that resulted from the load rejection. The cause of the event was due to the forces of nature (i.e., high winds and salt air). Please note the event occurred while at 32 percent reactor power. At that power level, the Turbine first stage pressure was approximately 200 psig. An RPS scram signal due to a Turbine Control Valves Fast Closure or Turbine Stop Valves closure would have occurred if the Turbine first stage pressure had been greater than 280 psig (i.e., the scram bypass setpoint for 45 percent of the normal first stage pressure). The scram bypass setpoint was changed from 280 psig to 108 psig via modification PDC 87-48 during RFO #7.

For LER 90-008-00, an automatic scram due to a load rejection occurred on May 13, 1990, at 1603 hours, while at 100 percent reactor power. The load rejection was caused by a momentary fault on the offsite 345 KV transmission system. The Generator's Loss Of Field Relay 240 detected the fault and immediately tripped the Generator without an expected 15 cycle time delay because one of it's components, the telephone relay coil, was defective. The relay had been calibrated and functionally tested on October 26, 1989. At that time, the operation of the coil was tested in accordance with the technical manual. The relay's time delay was built-in and not adjustable and was not required to be timed. The relay was installed during plant construction (c. 1972). The cause of the open coil was investigated and believed to be a random or age-related failure. The relay is the only one of its type (Westinghouse type KLF-1) installed at Pilgrim Station and was replaced with another type KLF-1 relay having an adjustable time delay. The relay's calibration sheet was revised to include a calibration of the adjustable time delay.

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For LER 91-024-00, a loss of preferred offsite 345 KV power occurred while shut down on October 30, 1991, at 1942 hours. The event occurred during a severe coastal storm (i.e., a northeaster). The loss of preferred offsite power occurred about two and one-half hours after a shut down. The loss of preferred offsite power resulted in designed responses including automatic actuations of the RPS, PCIS, RBIS, and EDGs 'A' and 'B'. The cause of the loss of preferred offsite power was the flashover of a 345 KV switchyard ACB 104 insulator column and separate operation of a stuck breaker circuit. The flashover was the result of environmental conditions (i.e., salt deposited on the insulator) due to a period of sustained dry northeasterly onshore winds. The storm that produced the dry winds was rare but more noteworthy was the period of sustained dry northeasterly onshore winds. The flashover caused switchyard ACBs 103, 104 and 105 to open. ACB 102 opened about 1.4 seconds later and as a result of the actuation of the ACB 105 stuck breaker circuit even though ACB 105 opened as designed. The most probable cause of the stuck breaker circuit operation was 345 KV electrical noise coupled into the stuck breaker circuit. Corrective actions taken included a washdown of switchyard insulators and the installation of a high speed recorder to monitor the ACB 105 circuitry. A loss of the secondary source of offsite power occurred at 1953 hours and an Unusual Event was declared at 2003 hours. The cause of the loss of 23KV secondary offsite power was also storm related when a tree fell onto a 23 KV line. Preferred offsite power was restored at 2142 hours and the Unusual Event was terminated at 2230 hours.

For LER 92-016-00, an automatic scram due to a load rejection occurred on December 13, 1992, at 1723 hours, while at 48 percent reactor power. At the time of the event, the Main condenser was being backwashed because of seaweed transported to the Intake Structure as a result of severe coastal storm winds and lunar tides. The load rejection was caused by 345 KV switchyard flashovers due to salt deposited during the storm. A flashover on the portion of the 345 KV bus located between the Main Transformer and ACBs 104 and 105 was the most probable cause of the event. A walkdown of the switchyard for evidence of flashover revealed evidence of arcing on three bushings installed on the phase 'C' busbar located between ACBs 102 and 105. The bushings were hand cleaned. The salt deposits were removed from 345 KV switchyard insulators by washing. The unit was returned to commercial service at 1350 hours on December 18, 1992.

A review was also conducted of Pilgrim Station LERs submitted since 1984 involving an unauthorized change of a trip setting. The review identified no instance of a similar event/condition.

A review was also conducted of Pilgrim Station reports submitted since 1972 involving a RV pressure event with no forced circulation in the RV. The review identified no similar event or condition.

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ENERGY INDUSTRY IDENTIFICATION SYSTEM (EIIS) CODES

The EIIS codes for this report are as follows:

COMPONENTS	CODES
Circuit Breaker, AC	52
Insulator	INS
Switchgear	SWGR
Vessel, Reactor	RPV

SYSTEMS	
Closed/Component Cooling Water System (RBCCW)	CC
Condensate System	SD
Condenser System	SG
Containment Isolation Control System (PCIS, RBIS)	JM
Engineered Safety Features Actuation System (PCIS, RBIS, RPS)	JE
Feedwater System	SJ
High Pressure Coolant Injection System	BJ
Low-Voltage Power System (600V and less)	EC
Main Steam System	SB
Main Turbine System	TA
Medium-Voltage Power System	EA
Plant Protection System (PRS)	JC
Post Accident Monitoring System	IP
Reactor Core Isolation Cooling System	BN
Reactor Recirculation System	AD
Reactor Water Cleanup (RWCU) System	CE
Residual Heat Removal System (SPC, SDC Modes)	BO
Standby Gas Treatment System (SGTS)	BH
Switchyard System (345 KV)	FK
Ultimate Heat Sink System (SSW)	BS

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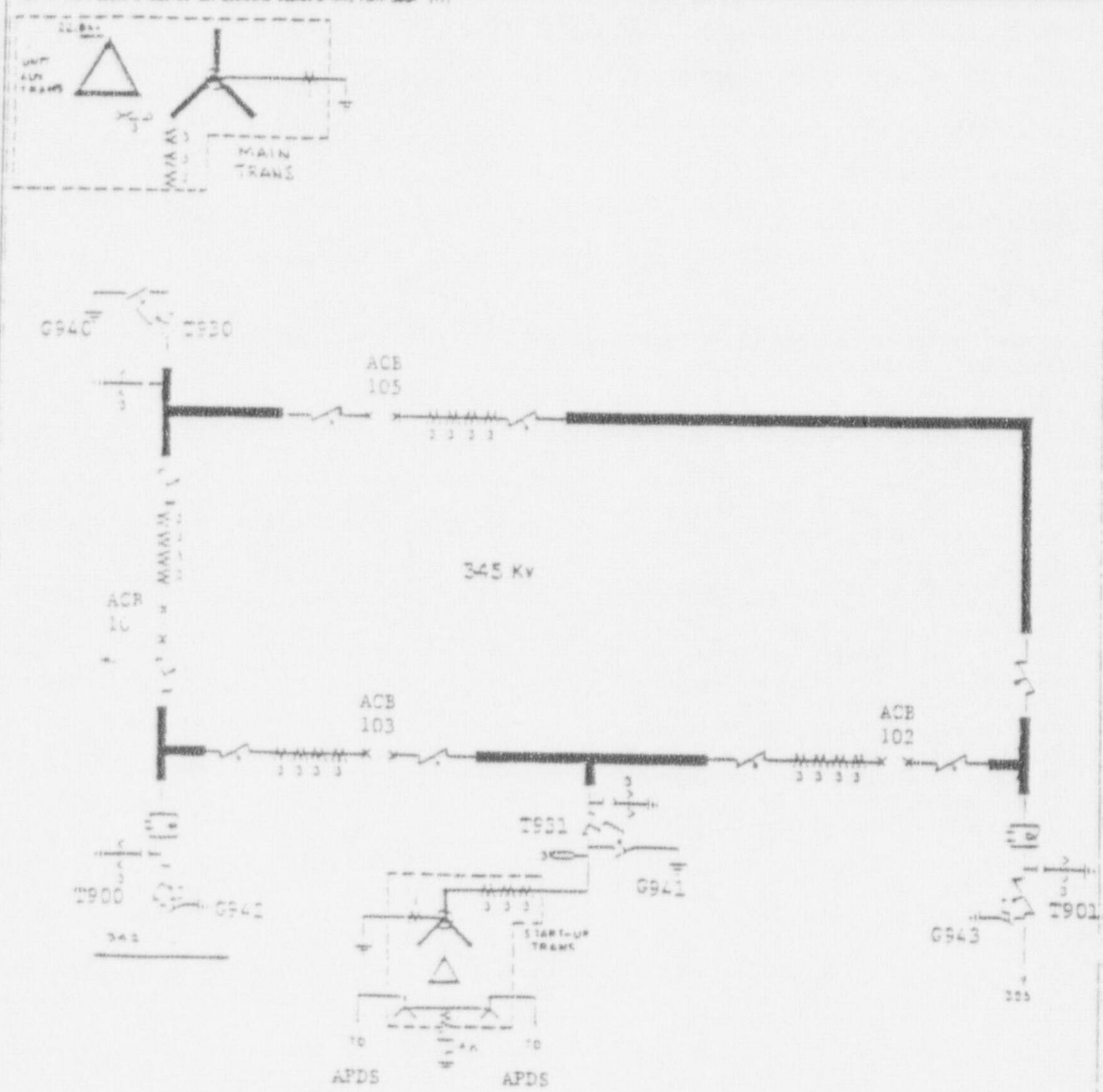

LER No. 313/93-003
Arkansas Nuclear One, Unit 1

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TITLE (4) Low Pressure Injection Pump Potentially Incapable Of Performing Its Recirculation Mode Function Due To Improper Pump/Motor Coupling Which Resulted From Inadequate Procedural Guidance

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
09	30	93	93	003	00	10	27	93	FACILITY NAME	DOCKET NUMBER

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (Check one or more) (11)			
		20.402(b)	20.405(c)	50.73(a)(2)(iv)	70.71(b)
POWER LEVEL (10)	000	20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	70.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER
		20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	Specify in
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	Abstract Below
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	and in Text

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
R. H. Scheide, Nuclear Safety and Licensing Specialist	501-964-5000

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE).	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On September 30, 1993, with the plant in cold shutdown, an engineering evaluation was completed which indicated that the "B" Decay Heat Removal/Low Pressure Injection pump (P-34B) might have been incapable of performing its recirculation mode function following a Loss of Coolant Accident (LOCA). This condition may have existed from May 24, 1993, while the plant was at power, until plant shutdown on September 9, 1993. On September 9, P-34B was declared inoperable due to high motor end bearing temperature. The engineering evaluation to determine past operability had been initiated on September 10 after identifying that the coupling hub on the pump shaft was installed approximately 0.316 inches too far toward the motor during the previous refueling outage (1R10). The evaluation concluded that a greasing evolution of the coupling hub on May 24, in conjunction with the coupling misalignment, created the degraded pump condition. P-34B was repaired and returned to service on September 10. The root cause of this condition was determined to be inadequate procedural guidance. Corrective actions include reviewing and revising appropriate maintenance procedures, as necessary.

NRC FORM 366 (5-92)

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Arkansas Nuclear One, Unit One	05000313	93	-- 003 --	00	2 OF 4

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

A. Plant Status

At the time this condition was identified, Arkansas Nuclear One, Unit One (ANO-1) was in Cold Shutdown. Reactor Coolant System (RCS) [AB] pressure was 210 psig and temperature was 180 degrees. Refueling outage 1R11 was in progress.

B. Event Description

On September 30, 1993, an engineering evaluation was completed which indicated that the "B" Decay Heat Removal/Low Pressure Injection (DHR/LPI) [BP] pump (P-34B) might have been incapable of performing its recirculation mode function following a Loss of Coolant Accident (LOCA). This condition may have existed from May 24, 1993, while the plant was at power, until plant shutdown on September 9, 1993.

The DHR/LPI system is designed to remove decay heat from the core and sensible heat from the RCS during the last stages of cooldown. It also provides a means of automatically injecting borated water into the reactor vessel for cooling the core in the event of a LOCA during power operation. During operation, the LPI system maintains core cooling for large breaks and operates independent of, and in addition to, the High Pressure Injection System (HPI) [BG]. Normal suction for LPI is from the Borated Water Storage Tank (BWST) with an alternate suction from the Reactor Building (RB) sump. This gives the system the ability to provide long-term core cooling in the recirculation mode following a LOCA after the BWST has been emptied.

At 0432 on September 9, with RCS temperature at 180 degrees, DHR pump P-34B was placed in operation in parallel with P-34A, which was already operating to support RCS cooldown for refueling outage 1R11. At 0530, the outboard motor bearing for P-34B alarmed on high temperature (180 degrees) and the pump was secured. The pump was run briefly to verify that the oil slinger ring was functioning properly and an oil sample was analyzed which indicated no abnormal wear products. P-34B was started at 1224, but the outboard motor bearing temperature again began to increase. At 1430, after the pump had been operating for approximately 2 hours and with bearing temperature approaching 190 degrees, P-34B was secured and declared inoperable. The Technical Specifications did not require both DHR pumps to be operable under the existing plant conditions and P-34A remained in service. P-34A had been started at 0042 and had been used continuously for RCS cooldown from 280 degrees with no abnormal indications. Therefore, its operability was not in question.

Troubleshooting efforts revealed that there was no bearing damage and that the pump and motor were not properly coupled. An engineering evaluation was initiated to determine if any past operability concerns existed. P-34B was repaired and returned to service on September 10.

During troubleshooting efforts, it was identified that the coupling hub on the pump shaft was installed approximately 0.316 inches too far toward the motor. This condition caused the motor to be pushed off of its magnetic center in the outboard direction. Since the pump thrust bearing is on the opposite side of the pump from the motor, thermal expansion of the pump shaft while pumping hot fluids would push the shaft coupling farther in the outboard direction, creating

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NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Arkansas Nuclear One, Unit One	05000313	93	-- 003 --	00	3 OF 4

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

increased thrust loading on the outboard motor bearing. Strip charts of outboard motor bearing temperature response during operation and surveillance testing from 1R10 until 1R11 were reviewed to determine what the bearing's final stabilization temperature would be during pump operation. Motor bearing temperatures are not required to be monitored during surveillance testing by the ASME code; however, they are recorded and maintained by ANO. The surveillances were successfully completed in accordance with procedures before bearing temperature stabilized; however, the strip chart data was used to analytically determine stabilization temperature. The data indicated normal and consistent bearing temperatures until May 24, 1993. This included pump operation at the end of 1R10 with RCS temperatures at approximately 160 degrees. The calculated bearing stabilization temperatures for surveillances conducted after this date were higher (but acceptable) than those for surveillances conducted before May 24. A review of maintenance records revealed that there had been a system mini-outage on May 24. The only work performed on P-34B during the outage that could possibly affect the pump or motor shaft was greasing of the coupling. This evolution consisted of pumping grease into the coupling. It should be pointed out that the coupling was "hand packed" during the 1R10 assembly. Due to the incorrectly installed coupling hub, a minor axial displacement or "stiffening" of the coupling's axial freedom as a result of the May 24 greasing evolution could have been enough to cause the motor shaft shoulder to come into close proximity with the bearing, subjecting it to thrust loading which would cause overheating of the bearing. The available data indicates that P-34B was operable and capable of performing all of its design functions prior to May 24, 1993, and capable of performing its LPI function thereafter. However, the pumps ability to function in the recirculation mode while pumping hot water from the RB sump is questionable after May 24, 1993.

C. Root Cause

In order to prevent thrust loading of the motor bearing, it is necessary to couple the motor to the pump with the motor in its magnetic center. Magnetic center is the position the motor would naturally seek if running uncoupled. The best way to determine magnetic center is to run the motor uncoupled. The plant procedure governing maintenance of P-34B instructs the craft to "scribe the motor shaft to mark magnetic center" prior to disassembly. At this point, the pump and motor are still coupled, but not running, and there is no guarantee that the motor is actually at its magnetic center. The assembly portion of the procedure directs the craft to set the motor shaft to magnetic center before coupling. The procedure did not provide the necessary guidance for accurately determining the motor's magnetic center. Therefore, the root cause of this condition was inadequate procedural guidance.

D. Corrective Actions

The P-34B pump and motor were properly coupled and the pump was returned to service on September 10, 1993.

The procedure which governs maintenance of the DHR/LPI pumps was revised to include appropriate guidance for identifying the motor's magnetic center and correctly coupling the pump to the motor.

A review of the design of the Containment Spray [BE] and High Pressure Injection [BQ] pumps was conducted which verified that they were not vulnerable to failure as a result of pump shaft thermal growth resulting from operation in the recirculation mode.

Applicable horizontal pump procedures for ANO-1 and ANO-2 will be reviewed and changes made as necessary to clarify the correct method for determining motor magnetic center. This action will be completed by January 30, 1994.

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NRC FORM 366A (5-92)

U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Arkansas Nuclear One, Unit One	05000313	93	-- 003 --	00	4 OF 4

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

E. Safety Significance

The most safety significant role of the DHR/LPI system is in the event of a LOCA, where one train can produce sufficient flow to cool the core in either the injection or recirculation mode.

P-34B was determined to have been capable of performing its LPI function throughout the previous fuel cycle and capable of performing its recirculation mode function until at least May 24, 1993. However, engineering evaluation concluded that the pump's ability to perform its recirculation mode function for longer than two hours subsequent to May 24 was questionable. Subsequent to May 24, the "A" LPI pump was only unavailable for a short time during one day for surveillance testing and minor maintenance. Since P-34B had been proven operable prior to this surveillance and was capable of performing its injection function as well as at least two hours in the recirculation mode (as demonstrated on September 9), ample time would have been available to restore P-34A to operable status. Considering that there was no period of time that both LPI pumps were unavailable to perform their design functions as a result of this condition, its safety significance is considered to be low.

Additional information regarding the reliability of ANO-1 Emergency Core Cooling Systems will be included in LER 50-313/93-005-00, which discusses deficiencies associated with the RB sump.

F. Basis For Reportability

Technical Specification 3.3.1 requires that two LPI pumps be operable whenever Containment integrity is required. Technical Specification 3.3.6 requires that if the conditions of 3.3.1 cannot be met, reactor shutdown shall be initiated and the reactor shall be in hot shutdown condition within 36 hours and in cold shutdown within an additional 72 hours. Since P-34B has been conservatively considered inoperable from May 24, 1993 until September 9, 1993 while containment integrity was required and reactor shutdown was not initiated, this condition is considered reportable pursuant to 10CFR50.73(a)(2)(i)(B) as operation prohibited by Technical Specifications.

G. Additional Information

There have been no previous similar events reported where deficient maintenance procedures have resulted in the inoperability of a safety related pump as a result of improper pump to motor coupling.

Energy Industry Information System (EIIS) codes are identified in the text by [XX].

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LER No. 316/93-007
Cook, Unit 2

NRC FORM 366 (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
DONALD C. COOK NUCLEAR PLANT - UNIT 2	0 5 0 0 0 3 1 6	1 OF 0 4

TITLE (4)

REACTOR TRIP FROM SPURIOUS TURBINE EXHAUST HOOD HIGH TEMPERATURE TRIP

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
0 8	0 2	9 3	9 3	— 0 0 7 —	0 0	0 9	0 1	9 3		0 5 0 0 0

OPERATING MODE (9)	1
POWER LEVEL (10)	0 7 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

	20.402(b)		20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
G. A. WEBER - PLANT ENGINEERING SUPERINTENDENT	6 1 6	4 6 5 - 5 9 0 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
X	T A	- - T S	M 2 3 5	Y						

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On August 2, 1993, at 1226 hours, the Unit 2 reactor tripped as a result of a main turbine trip, caused by a spurious actuation of the Exhaust Hood High Temperature Trip Switches. Investigation revealed that eight of nine Exhaust Hood High Temperature Trip Switch setpoints were found to be significantly below the normal trip setpoint. Investigation of the event determined that the method used to calibrate the switches may have caused the setpoint to be misadjusted, and that vibration can cause a downward shift in the setpoint. These factors, combined with a slight increase in hood temperatures and vibration levels which resulted from the removal of a main condenser half from service, are believed to have caused the spurious trip.

To prevent recurrence, the Main Turbine Exhaust Hood high temperature turbine trip was disabled. Written instructions for a manual turbine trip on receipt of a verified Main Turbine Exhaust Hood Extreme High Temperature Alarm have replaced the defeated automatic trip.

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NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
D. C. COOK NUCLEAR PLANT - UNIT 2	0 5 0 0 0 3 1 6	9 3	0 0 7	0 0	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Conditions Prior to Occurrence

Unit 2 was operating in Mode 1 at 70.5 percent of Rated Thermal Power. Condenser 'B' North water box had been removed from service within the previous 15 minutes.

Description of Event

On August 2, 1993, at 1226 hours, the Unit 2 reactor (EIIS/JE) tripped as a result of a Main Turbine (EIIS/TA) Exhaust Hood high temperature trip.

Following the turbine/reactor trip sequence, [turbine (EIIS/TA-TRB) trip, opening of the reactor trip breakers (EIIS/JE-BKR), insertion of reactor control rods (EIIS/BA-P), and automatic start of the auxiliary feedwater pumps (EIIS/BA-P,], Operations personnel immediately implemented Emergency Operating Procedure 2 OHP 4023.E-0 to verify proper response of the automatic protection systems and to assess plant conditions for appropriate recovery actions.

Abnormalities noted during the event included:

Feedwater valves (EIIS/BA-FCV) from the East Motor Driven Auxiliary Feed Pump (EIIS/BA) throttled further than expected after receiving a flow retention signal, requiring operator action to maintain correct flow rates. The Auxiliary Feedwater (AFW) flows from the other motor-driven and turbine-driven pumps were not affected and delivered flow in excess of that required for safety analysis concerns. Flow switches were subsequently recalibrated and flow retention intermediate valve positions were reset.

Main Steam Isolation Valves (EIIS/SB-ISV) started drifting closed following the reactor trip. The valves were promptly reopened. A review of several past trip reports indicates that this is not unusual and is an expected consequence following a trip due to actuator design. No corrective actions are planned.

Cause of Event

The turbine trip was initiated by a spurious actuation of the Turbine Exhaust Hood High Temperature Switches. Eight of nine switch actuation setpoints were found to be significantly lower than as-left condition recorded in August, 1992 when they were last calibrated.

The investigation of this event found that the calibration accuracy is affected by the ability to position the switch for bench calibration precisely as it will be positioned in the field. Any difference will affect the accuracy of the calibration. Calibration accuracy is also susceptible to the method by which heat is applied to the switch sensing element. The method used in the previous calibration (application of heat using a heat gun) may have allowed a difference to exist between the temperature sensed by the

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U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
D. C. COOK NUCLEAR PLANT - UNIT 2	0 5 0 0 0 3 1 6	9 3	— 0 0 7	— 0 0	0 3 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Cause of Event (Cont'd)

sensing element of the switch and that sensed by the calibration standard. It was also demonstrated by test that vibration can cause the switch to actuate below its setpoint.

Just 15 minutes prior to the event, cooling water to the "B" North Low Pressure Turbine (LPT) Condenser half was isolated to permit inspection for tube leakage. Removal of a condenser half from service has the effect of increasing hood temperature on the associated LPT and can also increase vibration levels. Although slightly elevated, both vibration and hood temperatures remained well within operating limits. However, the slight increase in these parameters, combined with the lower than normal as-found switch setpoints and the tendency of the switches to actuate prematurely when subjected to vibration, is believed to have caused the spurious trip.

Analysis of Event

This report is being submitted in accordance with 10 CFR 50.73, paragraph (a)(2)(iv), as an event that resulted in an unplanned automatic actuation of the Engineered Safety Features, including the Reactor Protection System.

The automatic protection responses, including reactor trip and its associated actuations were verified to have functioned properly as a result of the reactor trip signal. Feedwater valves from the East Motor Driven Auxiliary Feed Pump, which throttled further than expected, were under the control of the reactor operator, and readjusted as required in accordance with the reactor trip response procedure (E-O). The main steam isolation valves, which started drifting closed, were reopened promptly. Based on the above, it is concluded that the event did not involve an unreviewed safety question as defined in 10 CFR 50.59(a)(2) nor did it adversely impact the health and safety of the public.

Corrective Actions

A review by AEPSC and ABB personnel determined that the Turbine Exhaust Hood high temperature trip served no safety-related function. The trip had been originally installed as a means of tripping the turbine in the event of generator motoring, to prevent damage to the turbine generator. Following this review, the automatic main turbine trip from high exhaust hood temperature was disabled and replaced with instructions for a manual main turbine trip. On receipt of a Main Turbine Exhaust Hood Extreme High Temperature Alarm, and after verifying the extreme high temperature condition per the revised annunciator response procedure, the operator will trip the turbine.

The calibration method for the Turbine Exhaust Hood high temperature trip has been modified to use a water bath for heat application to provide assurance of a uniform heat medium.

NRC Form 366A (6-89)

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
D. C. COOK NUCLEAR PLANT - UNIT 2	0 5 0 0 0 3 1 6	9 3	— 0 0 7	— 0 0	0 4 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Corrective Actions (Cont'd)

Balance weights were added to the main turbine during unit startup to reduce vibration levels.

The East Motor Driven Auxiliary Feed Pump flow switches were recalibrated and flow retention intermediate valve positions were reset.

Failed Component Identification

Plant Designation: Low Pressure Turbine Exhaust Hood Temperature Switch Thermal Sensors
Manufacturer: Mercoid Corp.
Model: DA-37-804-6
EIIS Code: EIIS/TA-TS

Previous Similar Events

None

NRC Form 366A (6-89)

LER No. 334/93-013
Beaver Valley Unit 1

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Beaver Valley Power Station Unit 1	05000 3 3 4	1 OF 08

TITLE (4)
Unit 1 Reactor Trip and Required Shutdown, Dual Unit Loss of Offsite Power.

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									Beaver Valley Unit 2	05000 412
10	12	9 3	9 3	0 1 3	0 0	11	11	93	FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9): 1
POWER LEVEL (10): 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

20.402(b)		20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
L. R. Freeland, General Manager Nuclear Operations	4 1 2 6 4 3 - 1 2 5 8

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
A	FK	XXX	XXX	N					
B	AB	XXX	XXX	N					

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On 10/12/93 Unit 1 was operating at 100 percent power and Unit 2 was in a refueling outage with all fuel removed from the reactor vessel. At 1507 hours, Unit 1 experienced a large loss of offsite load when ten offsite feed breakers in the Beaver Valley switchyard opened as a result of an inadvertent underfrequency system separation actuation. The load reduction caused the Unit 1 turbine to trip on mechanical overspeed and resulted in a High Flux Rate Reactor Trip. The opening of the switchyard feed breakers and the resultant Unit 1 generator trip resulted in a loss of offsite power to Units 1 and 2. Both Unit 1 Emergency Diesel Generators (EDGs), and the required Unit 2 EDG, started and supplied their required loads. Unit 1 Auxiliary Feedwater actuated due to Low-Low Steam Generator Levels resulting from the Reactor Trip. Unit 1 was stabilized using the Emergency Operating Procedures. Following realignment of switchyard breakers, offsite power was restored to both units by 1522 hours. On 10/13/93, following a Unit 1 containment inspection, a Reactor Coolant System Pressure Boundary Leak was discovered on the Loop 1A cold leg vent valve RC-27. A Technical Specification Required cooldown was initiated and Mode 5 was entered at 0304 hours on 10/14/93.

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NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Beaver Valley Power Station Unit 1	05000 3 3 4	9 3	- 0 1 3 -	0 0	02 OF 08

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

DESCRIPTION OF EVENT

On October 12, 1993 Beaver Valley Unit 1 was operating at 100 percent power with normal station loads being supplied from the unit station service transformers. Unit 2 was in the Fourth Refueling Outage with all of the fuel removed from the reactor vessel and stored in the spent fuel pool. Required Unit 2 electrical loads were being supplied from offsite power via backfeed through the main unit transformer. Power was also available to Unit 2 via the 2A system station service transformer. The 2B system station service transformer was removed from service for maintenance.

At 1507 hours, Unit 1 experienced a loss of the majority of its electrical load when ten offsite feed breakers in the Beaver Valley switchyard opened unexpectedly. The loss of these offsite breakers, which included the in-service Beaver Valley Unit 2 main output breaker (PCB 362) and one Unit 1 output breaker (PCB 341), caused Unit 1 generator load to drop from approximately 810 net MWe to 85 net MWe. The loss of load caused the turbine speed to increase until the turbine tripped on mechanical overspeed (setpoint 1998 rpm). The Turbine Overspeed Protection (OPC) trip actuation operated but was not required since the turbine had already tripped on mechanical overspeed. Historical computer data from the event indicated turbine peak speed at 2051 rpm. The increased turbine speed caused an increase in generator output frequency forcing a corresponding increase in the Reactor Coolant Pump (RCP) speed. A transient Reactor Coolant System flow increase resulted from the RCP speed change. This flow transient translated into a positive reactivity change leading to a High Flux Rate Reactor Trip. All Control Rods inserted fully.

Following the Unit 1 Reactor Trip, the No. 1 Emergency Diesel Generator (EDG) auto-started, due to Train A Emergency 4KV bus (AE) undervoltage; however, the undervoltage condition was not sufficient to require the AE bus to shed its loads and cause EDG sequencing. All three Auxiliary Feedwater (AFW) Pumps (two motor driven and one steam driven) auto-started due to the shrink in steam generator levels. All three Reactor Coolant Pumps tripped on bus underfrequency as the Main Unit Generator speed reduced. Thirty seconds following the turbine trip, the generator output breakers opened as designed. The Unit 1 Main Unit Generator had been the only normal power source for Unit 1 and Unit 2 electrical loads since the underfrequency separation scheme actuated. When the Unit 1 generator tripped, Unit 1 and 2 both experienced a loss of offsite power.

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NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION
(5-92)

APPROVED BY OMB NO. 3150-0104
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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

Following the loss of offsite power, Unit 1 normal 4KV busses de-energized and shed their loads, and the Unit 1 No. 2 EDG started. Both Unit 1 EDGs then properly sequenced loads on their respective busses as designed, including charging, river water, component cooling, and AFW pumps. Unit 1 operators stabilized the plant using the Emergency Operating Procedures (EOPs). Initially, a natural circulation cooldown was established as no power was available for the Reactor Coolant Pumps. The Main Steamline Isolation Valves were closed manually, in accordance with Emergency Operating Procedure E-0, as there was no position indication available for the Reheater Steam Supply Isolation Valves during the loss of offsite power. Operators then utilized Steam Generator Atmospheric Steam Release Valves to remove decay heat and control the cooldown. At 1517 hours, the Duquesne Light Company System Operations Department restored offsite power by re-closing the switchyard breakers. The Unit 1 control room crew then established forced Reactor Coolant System cooling by starting Reactor Coolant Pump 1C. The AE and DF emergency busses were realigned to offsite power and the EDGs were secured.

At the initiation of the event at Unit 2 (prior to the loss of offsite power) the standby Primary Component Cooling Water Pump (2CCP-P21C) auto-started on low header pressure, the Unit 2, 2-1 Emergency Diesel Generator (EDG) started on degraded bus voltage, and the 2A and 2B normal 4KV busses transferred to offsite power. The dual unit Control Room Emergency Pressurization System actuated due to a loss of voltage to the Control Room Area Radiation Monitor 2RMC-RQ201. Following the Unit 1 main unit generator trip and the resultant loss of offsite power, the Unit 2, Train A emergency 4KV bus (2AE) shed its loads and the Unit 2, 2-1 EDG properly sequenced all available loads. Low Head Safety Injection Pump 2SIS-P21A auto-started via the EDG sequencer as designed, but no water was injected since the discharge valves were closed for refueling. The pump was secured eighty-four seconds after it started. The Unit 2 Train B emergency 4KV bus (2DF) and associated 2-2 EDG had been removed from service for outage related maintenance and were not required to be operable. Following restoration of offsite power at Unit 2 (1522 hours), the 4KV system was reenergized and the Train A normal to emergency 4KV tie breakers were closed. The Unit 2, 2-1 EDG was unloaded and output breaker opened at 1535 hours.

Following the Reactor Trip, Unit 1 was in Hot Standby, Mode 3. At 0345 hours, on October 13, 1993, a Unit 1 containment entry was made to perform routine, post trip, leak inspections. During this inspection, a leak was identified at the Loop 1A Cold Leg Vent Valve (RC-27). This valve is also used as a connection point for disc pressurization for isolating the 1A reactor coolant loop. A subsequent entry was made to perform more detailed inspections. A review of photographs and discussion by Mechanical Maintenance and Operations, led to the conclusion that potential Pressure Boundary Leakage existed.

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Unit 1 then commenced a cooldown to Cold Shutdown per Technical Specifica*.on 3.4.6.2.a, and declared an Unusual Event per the Emergency Preparedness Plan. Unit 1 entered Mode 5 at 0304 hours on October 14, 1993 and the Unusual Event was terminated at that time. Upon inspection, RC-27 was found to have a through-wall crack at the fillet weld, verifying Pressure Boundary Leakage.

CAUSE OF EVENT

The cause of the loss of offsite power event was personnel error. A three man Electrical Maintenance crew, consisting of a Crew Leader, an Electrical Maintenance Technician, and a Senior Engineer, were performing scheduled outage maintenance on Unit 2 Main Output Breaker PCB 352. During the verification of auxiliary contact alignment of the PCB 352 breaker, an inadvertent application of 125 Volt DC actuated an underfrequency separation scheme in the Beaver Valley switchyard. This resulted in the opening of seven 345 KV feed breakers (including Unit 1 Main Unit Output Breaker PCB 341) and three 138 KV feed breakers, initiating the loss of electrical load at Unit 1.

A cracked mechanical linkage, for the center stack auxiliary contacts of breaker PCB 352, was replaced the morning of October 12, 1993. At 1400 hours, during timing tests of the breaker's mechanism, the Beaver Valley Relay Group Supervisor notified the maintenance crew that reset relays associated with PCB 352, located in the Unit 2 Relay Room, were overheating. It was determined that the auxiliary contacts, located in the center stack of a three stack assembly, were in the wrong position. This caused the operate and reset coils of the reset relays in the relay room to be energized simultaneously, resulting in overheating. The maintenance crew then visually checked the auxiliary contacts of PCB 352 on the stack where the cracked arm was replaced. They determined that the stack's shaft was rotated out of position. The problem was corrected and the auxiliary contact linkage reassembled. Using a multimeter on continuity scale and site electrical prints, the crew then started checking the three auxiliary contacts connected to this linkage for other possible misalignment problems. During this verification, underfrequency tripping relays were actuated when 125 Volt DC from one set of contacts was inadvertently connected to another set of contacts in the underfrequency separation scheme, via the multimeter.

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

The cause of the Unit 1 Pressure Boundary Leak was determined to be due to a fillet weld failure. Samples of pipe removed from RC-27 were sent to a laboratory for failure analysis. The results indicated that the weld failed due to the presence of an imbedded flaw that propagated inward and outward, causing a through-wall crack. RC-27 was inspected during the last refueling outage (9R) in response to a vendor recommendation concerning disc pressurization line socket weld cracking. A linear indication was found at that time and was believed to have been satisfactorily repaired. A minor design change was also implemented in 9R to reduce the pipe length, thereby reducing the probability of pipe failure due to cyclic loads.

CORRECTIVE ACTIONS

The following corrective actions have been initiated as a result of the event:

1. Detailed root cause analyses were performed to determine the cause of the switchyard transient and Reactor Coolant System leak.

2. Interim administrative controls over work performed in the Beaver Valley switchyard were issued that require Operations Department approval of all work activities in the switchyard.

3. Long term administrative controls governing work in the switchyard will be established by the managers responsible for switchyard activities.

4. The Underfrequency System Separation scheme in the Beaver Valley switchyard has been disabled. At the time the separation scheme was implemented, there was sufficient electrical load available in the local vicinity to maintain Beaver Valley Unit 1 on-line and separated from the rest of the system. As a result of load changes, this separation scheme is no longer valid.

5. Unit 1 Loop 1A Cold Leg Vent Valve (disc pressurization connection) RC-27 was removed, plugged, capped, and welded. All other disc pressurization taps penetrating loop stop valves were inspected at both Beaver Valley units and found to be satisfactory. Samples removed from RC-27 indicate that the failure was due to an imbedded flaw. Further evaluation will be performed to determine the need for additional corrective actions.

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

REPORTABILITY

Beaver Valley Units 1 and 2 reported the Reactor Trip and Dual Unit Loss of Offsite Power to the Nuclear Regulatory Commission, via the Emergency Notification System, at 1843 hrs on October 12, 1993, and Unit 1 reported the Unusual Event at 0811 hours on October 13, 1993. The Unit 1 Reactor Trip and Dual Unit Loss of Offsite Power were reported in accordance with 10 CFR 50.72.b.2.ii. (Reactor Protection System and Engineered Safety Feature Actuations) and the Unit 1 Unusual Event was reported in accordance with the Emergency Preparedness Plan and 10 CFR 50.72.b.1.i.A. (Technical Specification Required Shutdown). This written report is being submitted in accordance with 10 CFR 50.73.a.2.iv. and 10 CFR 50.73.a.2.i.

SAFETY IMPLICATIONS

There were minimal safety implications at Units 1 or 2 as a result of this event. At Unit 1 the Reactor Protection System functioned as designed and actuated a reactor trip. The operating crew successfully stabilized the plant following the reactor trip using the Emergency Operating Procedures. Normal post-trip evaluations were performed and all ESF equipment was determined to have functioned as designed. The event is bounded by the following Updated Final Safety Analysis (UFSAR) Sections and plant response was deemed to be within the analysis results and conclusions: 14.1.7 (Loss of External Electrical Load and/or Turbine Trip), 14.1.8 (Loss of Normal Feedwater), 14.1.11 (Loss of Offsite Power to the Station Auxiliaries (Station Blackout)), 14.1.12 (Turbine - Generator Accidents), and 14.2.9 (Complete Loss of Forced Coolant Flow).

Unit 2 was in a Refueling Outage with all of the fuel removed from the reactor vessel and stored in the spent fuel pool. The 2-2 Emergency Diesel Generator (EDG) and the Train B emergency 4KV bus were on clearance. On the loss of off-site power all required Train A station loads were properly sequenced by the 2-1 EDG. At Unit 2 the event was bounded by UFSAR Section 15.2 6 (Loss of Nonemergency AC Power to the Plant Auxiliaries (Loss of Offsite Power)).

There were also minimal safety implications to the public as a result of the Reactor Coolant Pressure Boundary leakage. All leakage was contained inside the Containment Building. Recent Reactor Coolant System Water Inventory Balance Tests, prior to the event, had shown unidentified leakage at less than 0.1 gpm. This event was bounded by Unit 1 UFSAR Section 14.3.1 (Loss of Reactor Coolant From Small Ruptured Pipes or From Cracks in Large Pipes Which Actuates Emergency Core Cooling System). Emergency Core Cooling was not actuated for this event.

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NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95
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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

DIESEL GENERATOR RELIABILITY

Both Unit 1 emergency diesel generators and the operable Unit 2 emergency diesel generator, properly started and sequenced all available loads at the proper times as designed for a loss of offsite power. The following is a summary of the past 20, 50 and 100 start and load demands for Unit 1 and 2 emergency diesel generators, trended in accordance with NUMARC 87-00 Rev. 1, Appendix D (Data as of September 30, 1993):

$$\text{Reliability} = 1 - \frac{\text{Number of Valid Failures}}{\text{Number of Valid Demands}}$$

Unit 1

Past 20 Start Demands: 1 = 1 - 0/20
Past 50 Start Demands: 1 = 1 - 0/50
Past 100 Start Demands: 1 = 1 - 0/100

Past 20 Load Demands: 1 = 1 - 0/20
Past 50 Load Demands: 1 = 1 - 0/50
Past 100 Load Demands: 0.99 = 1 - 1/100

Unit 2

Past 20 Start Demands: 1 = 1 - 0/20
Past 50 Start Demands: 1 = 1 - 0/50
Past 100 Start Demands: 1 = 1 - 0/100

Past 20 Load Demands: 1 = 1 - 0/20
Past 50 Load Demands: 1 = 1 - 0/50
Past 100 Load Demands: 1 = 1 - 0/100

Note: Subsequent to this summary, Unit 2 experienced relay failures on both diesel generators, which are not listed above, but would have prevented sequencer loading on a safety injection signal. These will be reported in a subsequent Unit 2 Licensee Event Report on the diesel generator failures.

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(5-92)

U.S. NUCLEAR REGULATORY COMMISSION

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LICENSEE EVENT REPORT (LER)
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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

PREVIOUS SIMILAR EVENTS

No similar events have previously occurred at Beaver Valley Units 1 and 2 involving a reactor trip and loss of offsite power.

Unit 1 has previously reported two events involving a required plant shutdown due to Reactor Coolant System (RCS) Pressure Boundary leakage:

1. LER 1-88-016 "Unit Shutdown Due to Pressure Boundary Leakage." This event involved a failed weld on the line near an RCS seal injection drain valve.

2. LER 1-91-002 "Reactor Coolant System Pressure Boundary Leakage Results in Plant Shutdown." This event involved the failure of a socket weld on the Loop 1B Cold Leg Vent Valve (disc pressurization connection).

NRC FORM 366A (5-92)

LER No. 339/93-002
North Anna Unit 2

NRC FORM 366 (6-89) — U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): North Anna Power Station Unit 2

DOCKET NUMBER (2): 0 5 0 0 0 3 3 9

PAGE (3): 1 OF 0 4

TITLE (4): AUTOMATIC REACTOR TRIP INITIATED FROM A TURBINE TRIP DUE TO AN OVER EXCITATION OF THE MAIN GENERATOR

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 4	1 6	9 3	9 3	- 0 0 2 -	0 1	0 8	1 2	9 3		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

☐ 20.402(b)	☐ 20.405(c)	☒ 50.73(a)(2)(iv)	☐ 73.71(b)
☐ 20.405(a)(1)(i)	☐ 50.36(c)(1)	☒ 50.73(a)(2)(v)	☐ 73.71(c)
☐ 20.405(a)(1)(ii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(vii)	☐ OTHER (Specify in Abstract below and in Text, NRC Form 366A)
☐ 20.405(a)(1)(iii)	☐ 50.73(a)(2)(i)	☐ 50.73(a)(2)(viii)(A)	
☐ 20.405(a)(1)(iv)	☐ 50.73(a)(2)(ii)	☐ 50.73(a)(2)(viii)(B)	
☐ 20.405(a)(1)(v)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME: G. E. Kane

TELEPHONE NUMBER: AREA CODE 7 0 3 — 8 9 4 - 2 1 0 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	T B	B G	W 1 2 0	Y	X	S J	R V	C 7 1 0	Y
X	J D	C H A	W 1 2 0	Y	X	S J	I L	G 0 8 0	N

SUPPLEMENTAL REPORT EXPECTED (14)

☐ YES (If yes, complete EXPECTED SUBMISSION DATE) ☒ NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On April 16, 1993, at 0717 hours with Unit 2 in Mode 1, 100 percent power, an automatic reactor trip occurred as a result of a turbine trip. Emergency procedures were entered and immediate actions were performed. Subsequently, the operating crew became concerned with the reactor coolant system (RCS) cooldown when temperature decreased to approximately 540 degrees F. To reduce the Steam Generator feedwater addition rate and stabilize the RCS temperature the ATWS Mitigation System Actuation Circuitry was reset and the Auxiliary Feed Water (AFW) pumps were secured before steam generator levels were restored above the automatic start setpoint. Defeating the automatic start capability of the AFW pumps is prohibited by Technical Specifications. A 4 hour report was made to the NRC at 1055 hours pursuant to 10CFR50.72 (b)(2)(ii) & (iii)(A). The event is reportable as an Engineered Safety Feature System actuation pursuant to 10CFR50.73 (a)(2)(iv) & (v).

The cause of the turbine trip/reactor trip was a malfunction in the main generator voltage regulator circuitry. The cause of defeating the AFW system during the event was a result of personnel error.

No significant safety consequences resulted from the reactor trip because reactor protection safety systems responded as designed. Disabling the AFW pumps did not present a significant safety consequence because the heat sink was maintained throughout the event. Therefore, the health and safety of the public were not affected at any time during this event.

NRC Form 366 (6-89)

NRC FORM 366A (6-89)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION		ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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North Anna Power Station Unit 2	0 5 0 0 0 3 3 9	9 3	— 0 0 2	— 0 1	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

1.0 Description of the Event

On April 16, 1993, at 0717 hours with Unit 2 in Mode 1, 100 percent power, an automatic reactor trip occurred from a turbine trip due to a malfunction in the main generator voltage regulator circuitry (EIIS System TB, Component TG). Emergency procedures were entered and immediate actions were performed. The Auxiliary Feedwater Pumps (AFW) (EIIS System BA, Component P) automatically started on Lo Lo Steam Generator (SG) (EIIS System AB, Component SG) level. During subsequent recovery actions of the reactor trip response procedure it was noted that the reactor coolant system (RCS) was experiencing a cooldown due to feeding the SGs with relatively cold water from the AFW system. The operating crew became concerned with the RCS (EIIS System AB) cooldown rate when temperature decreased to approximately 540 degrees F. To reduce the SG feedwater (EIIS System SJ) addition rate and stabilize the RCS temperature, the ATWS Mitigation System Actuation Circuitry (EIIS System JC) was reset, and the AFW pumps were secured in a manner that rendered them inoperable before SG levels were restored above the automatic start setpoint.

After securing the AFW, Main Feed Water (MFW) was the makeup water source for the SGs. Subsequently, approximately 19 minutes later, the emergency procedure reader noticed that the AFW pump status did not conform to the appropriate emergency procedure step and immediately notified the Shift Supervisor (SS) who directed the pumps to be returned to AUTO. Defeating the automatic start capability of the AFW pumps is prohibited by Technical Specifications. A 4 hour report was made to the NRC at 1055 hours pursuant to 10CFR50.72 (b)(2)(ii) & (iii)(A). The event is reportable as an Engineered Safety Feature System actuation pursuant to 10CFR50.73 (a)(2)(iv) & (v).

2.0 Significant Safety Consequences and Implications

No significant safety consequences resulted from the reactor trip because reactor protection safety systems responded as designed. No significant safety consequences resulted from disabling the AFW pumps for approximately 19 minutes because the heat sink was maintained throughout the event. The AFW pumps could have been made available immediately by manual operator action. The AFW system was always under the cognizance of Licensed Operator. Main feedwater was also available throughout the event and used to provide makeup to the SGs. Therefore, the health and safety of the public were not affected at any time during this event.

3.0 Cause of the Event

The cause of the turbine trip/reactor trip was the result of a malfunction in the main generator voltage regulator circuitry. An exciter field forcing condition, which led to the trip, was attributed to a combination of erratic behavior of the Minimum Excitation Limiter (MEL), and/or Voltage Error Detector (VEO) and failure of the damping card due to a corroded gain potentiometer within the logic drawer of the voltage regulator.

NRC Form 366A (6-89)

NRC FORM 366A (6-89)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92
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TEXT (If more space is required, use additional NRC Form 366A's) (17)

3.0 Cause of the Event (continued)

The cause of defeating the AFW system was personnel error. Insufficient command and control of the unit trip response and inadequate communications between the operations crew members resulted in defeating the AFW pump, when a valid start signal was present.

The policy associated with defeating equipment or system automatic safety functions was misunderstood. In addition, management expectation of communications and problem solving using all crew members was not effectively conveyed.

4.0 Immediate Corrective Actions

An inspection of the turbine/generator was performed to determine the extent of the voltage regulator malfunction. Operating parameters from the voltage regulator were gathered for analysis.

Following the reactor trip Emergency Procedure 2-E-0, Reactor Trip or Safety Injection, was entered and the immediate actions performed. The Shift Supervisor immediately directed that the AFW pumps be returned to the automatic position when the condition was identified.

5.0 Additional Corrective Actions

Troubleshooting of the voltage regulator circuitry determined that the MEL, VEO, and damping cards were not operating properly and were replaced. In addition, an imbalance on the firing circuit drawers was corrected and the overexcitation protection setpoint was recalibrated. The vendor electrical maintenance procedure was enhanced to include preventative maintenance activities.

The individuals involved with the AFW pump condition were coached on the station's policy for defeating equipment automatic functions. These individuals were removed from licensed duties and received remediated training designed to enhance their control room communication skills and their understanding of the control room command and control structure during emergency procedure implementation.

6.0 Actions to Prevent Recurrence

The actions taken regarding the voltage regulator are sufficient to preclude recurrence.

Requirements are in place to ensure the event is discussed in the Licensed Operator Requalification Program. A root cause was performed and corrective actions are being reviewed by management for implementation as appropriate. The training reviews and the actions taken regarding the individuals involved are sufficient to preclude recurrence.

NRC Form 366A (6-89)

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

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7.0 Similar Events

LER N2-86-008-00 identified a reactor trip from a turbine trip as a result actuation of a main generator differential lockout relay upon loss of an excitation field signal. The signal was caused by failure of the permanent magnet generator in the main generator excitation system.

8.0 Additional Information

Component failures resulting from the automatic reactor trip included: Source Range Channel N31 failed low, 1A Feedwater Heater relief valve lifted and would not reset until the feedwater heater was isolated and depressurized, and the "B" MFW Pump breaker indicating lights did not work in the Control Room.

Corrective actions included replacement of the Source Range Channel detector, 1A Feedwater Heater relief valve, and the "B" MFW Pump breaker lights.

Unit 1 was in Mode 3, hot standby, returning to power operations following a refueling outage and was not affected by the event.

NRC Form 366A (6-89)

LER No. 370/93-008
McGuire Unit 2

NRC FORM 366
U.S. NUCLEAR REGULATORY COMMISSION
(5-92)

APPROVED OMB NO. 3150-0104
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[illegible]

LICENSEE EVENT REPORT (LER)

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TITLE (4) A Unit 2 Reactor Trip Occurred Due To A Loss Of Offsite Power Caused By A Possible Unanticipated Environmental Interaction, Vendor Fabrication Deficiency, Deficient Documentation, Inadequate Surveillance Program, And An Inappropriate Action.

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										05000
12	27	93	93	008	00	01	26	94	N/A	05000

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO REQUIREMENTS OF 10CFR (Check one or more of the following) (11)							
POWER LEVEL (10)	100%		20.402(b)		20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
			20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
			20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
			20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
R. J. Deese, Manager, McGuire Safety Review Group	704	875-4065

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
B	HBC	VALVOP	C311	YES		E	HBC	VALVOP	C311	YES
B	HBC	ICNTRL	B040	YES		X	HBC	ICNTRL	W120	YES

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single-space typewritten lines (16)

On December 27, 1993, Unit 2 experienced a loss of bus line 2B due to a failed insulator. This was followed by a failure of the Unit 2 Turbine Generator to runback. Bus line 2A subsequently tripped on an overcurrent condition. A Reactor Trip occurred at 2207 due to a Power Range High Flux Rate Signal, followed by a Turbine Generator trip and the opening of the 2A Generator breaker. This resulted in a loss of Unit 2 offsite power. The subsequent cooldown resulted in a Safety Injection and Main Steam (SM) line isolation at 2214. Valve 2SM-5, SM Isolation Valve Steam Line B, failed to close fully, resulting in the 2B Steam Generator emptying. Control Room personnel declared an Unusual Event at 2222. As a conservative measure, OPS Control Room personnel activated the Technical Support Center, Operations Support Center, and staffed the Emergency Operations Facility. Offsite power was restored to Unit 2 at approximately 2343. Causes of Possible Unanticipated Environmental Interaction, Vendor Fabrication Deficiency, Deficient Documentation, Inadequate Surveillance Program, and Inappropriate Action are assigned to the event. Unit 2 was in Mode 1 (Power Operation) at 100 percent power, prior to the event. Corrective actions included repairs to the failed SM isolation valve and replacement of the failed bus line insulator. Unit 2 returned to Mode 2 (Startup) operation on January 6, 1994, at approximately 2200.

NRC Form 366

EVALUATION:

Background

McGuire Nuclear Station, Unit 2, consists of the generating unit and auxiliary equipment. The unit generates power at a voltage of 24KV that is delivered through two half-size step-up transformers [EIIS:XMFR] to the McGuire 525KV switchyard [EIIS:FK] by overhead transmission lines. The output of the unit is then delivered into the Duke transmission system through switchyard power circuit breakers (PCB) [EIIS:52] in a breaker and a half configuration and transmission lines.

The following discussion describes the intended response of the turbine [EIIS:TRB] generator after a loss of one bus line:

> In the event a fault occurs in one of the two independent circuits, the switching station PCB and the generator PCB in the affected circuit trip. The 6.9KV Normal Auxiliary Power System switchgear assemblies normally being fed from the affected circuit automatically transfer to the full-size auxiliary transformer supplied from the other independent circuit. The generator automatically runs back to half load, thereby maintaining non-interrupted ties between the transmission system and the 6.9KV Normal Auxiliary Power System, which is supplied from one auxiliary transformer during this per.od.

Main steam (SM) [EIIS:SB] isolation valves (MSIV) [EIIS:ISV] are provided in each Steam Generator (S/G) [EIIS:SG] steam line immediately downstream of the code safety valves [EIIS:RV] to isolate each individual S/G in the event of a steam line rupture. The MSIVs close on high-high Containment pressure and/or on high steam line pressure rate of change or low steam line pressure as the result of a SM line rupture between the S/G and the Turbine [EIIS:TRB] steam stop valves [EIIS:V].

Description of Event

On December 27, 1993, at 2206, Unit 2 Operations (OPS) Control Room (C/R) [EIIS:NA] personnel received an annunciator [EIIS:ANN] alarm [EIIS:ALM] for loss of bus line 2B. At the time the annunciator was received, Unit 2 was operating in Mode 1, at 100 percent power. The only significant equipment not in service at the time of the event was valve 2SV-7, "C" SM Power Operated Relief Valve (PORV), which was tagged out for implementation

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of a Nuclear Station Modification (NSM). At the time 2B bus line was lost, OPS C/R personnel observed that the Turbine/Generator (T/G) [EIIS:TG] was not running back as designed.

While OPS C/R personnel were in the process of initiating a manual T/G load reduction, but prior to any actual manual load reduction, bus line 2A was also lost. A Reactor trip occurred due to a Power Range High Flux Rate signal. The Reactor trip was followed by a T/G trip and the opening of the 2A generator breaker. This resulted in a loss of Unit 2 offsite power. At this point OPS C/R personnel implemented the Unit 2 emergency procedures, beginning with procedure EP/2/A/5000/01, Reactor Trip or Safety Injection.

The loss of power to 4.16KV essential busses 2ETA and 2ETB caused the Train 2A and 2B Blackout logic to be initiated. Emergency Diesel Generators (D/G) [EIIS:EK] 2A and 2B were automatically started as designed and when the D/G 2A and 2B breakers closed, both Unit 2 4.16KV vital busses were re-energized. The Reactor Coolant (NC) [EIIS:AB] Pumps [EIIS:P], which are supplied from non-vital power, coasted down. Plant cooldown proceeded by natural circulation.

Both the Train 2A and 2B Motor [EIIS:MO] Driven (MD) Auxiliary Feedwater (CA) [EIIS:BA] pumps, along with the Turbine Driven (TD) CA pump, started and supplied water to the S/Gs.

NC system temperature and pressure quickly dropped below no load values following the Reactor trip. This was due to the introduction of CA system flow into the S/Gs and steam demand. Those steam demands include various steam line drain valves which are downstream of the MSIVs, that fail open on a loss of power, and valve 2SM-15, SM Supply to Moisture Separator Reheaters Block, which failed as is on a loss of power. An NSM had been implemented to allow the steam line drains upstream of the MSIVs to fail closed upon a loss of power.

NC system temperature and pressure continued to decrease and by 2214, a Safety Injection (SI) on low Pressurizer (PZR) [EIIS:PZR] pressure occurred. The low PZR pressure SI signal was followed immediately by a low steam line pressure SI signal. With steam line pressure at the low pressure setpoint, a SM Isolation signal was also generated at 2214, to isolate the steam lines.

Following the SM isolation the NC system cooldown continued due to continuing CA system flow and decreasing steam pressure. OPS C/R personnel, while responding to the cooldown,

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noted that valve 2SM-5, MSIV Steam Line B, was not fully closed. It was later determined that valve 2SM-7 MSIV Steam Line A, exhibited some leakage, although to a much smaller degree than valve 2SM-5. At approximately this same time personnel were dispatched to attempt to manually close valves 2SM-5, 2SM-15, along with valves 2SM-83, 89, 95, and 101 (A,B,C,D SM Line Drain). Instrument and Electrical (IAE) personnel subsequently placed air line jumpers on valves 2SM-83, 89, 95, and 101, in an attempt to close these valves. It was later determined that this action actually opened valves 2SM-83, 89, 95, and 101, rather than closed them. This action had no appreciable effect on the cooldown rate.

At 2222 the OPS Shift Supervisor declared a Notification Of Unusual Event (NOUE) in accordance with the McGuire Nuclear Station Emergency Plan. During the notification process the State/County notification form from procedure RP/0/A/5700/01, Notification Of Unusual Event, was also sent to the NRC. Procedure RP/0/A/5700/10, NRC Immediate Notification Requirements, was not completed at that time.

At 2223 CA system flow was stopped to all four S/Gs in accordance with the emergency procedures, and with valve 2SM-5 partially open, 2B S/G began to empty. OPS C/R personnel subsequently isolated CA system flow to 2B S/G. At 2224, valve 2SM-15 began to close. These actions caused the NC system cooldown to begin to stabilize. At 2225, OPS C/R personnel had transitioned through the emergency procedures to procedure EP/2/A/5000/3.1, SI Termination Following Excessive Cooldown.

Between 2228 and 2249 the PZR PORVs cycled to control increasing PZR pressure which was due to the mass addition to the NC system resulting from the SI. Later in the event, OPS C/R personnel took manual control of a PZR PORV to reduce the differential pressure across the 2B S/G tubes to 1600 psid in accordance with the emergency procedures. During the process of reducing NC system pressure, at approximately 2326, the PZR Relief Tank (PRT) [EIIS:TK] Rupture Disks relieved to prevent overpressurization of the PRT. The release of pressure from the PRT resulted in a Unit 2 lower compartment pressure increase, which caused the opening of a number of lower Ice Condenser [EIIS:NF] doors. This was indicated by increasing Ice Condenser temperatures at 2330.

At 2342 bus line 2A was re-energized and offsite power was restored. On December 28, 1993, at approximately 0011, OPS C/R personnel made a decision to activate the McGuire Technical Support Center (TSC) and Operations Support Center (OSC); and to staff the Emergency Operations Facility (EOF), to provide assistance to OPS C/R personnel. This activation was not required for a Notification Of Unusual Event.

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At 0018, 4.16KV essential bus 2ETB was re-energized from offsite power. Essential bus 2ETA was re-energized from offsite power at 0032. At 0137, NC pump 2A was started, restoring forced flow through the Unit 2 Reactor core.

At 0330, the TSC reached a decision to take Unit 2 to Mode 5, Cold Shutdown.

At 1201, sampling of 2B S/G was completed, confirming there was no primary to secondary leakage indicated. The TSC was deactivated on December 28, 1993, at 1245.

Conclusion

This event is assigned causes of Possible Unanticipated Environmental Interaction, Vendor Fabrication Deficiency, Deficient Documentation, Inadequate Surveillance Program, and Inappropriate Action.

A cause of Possible Design, Manufacturing/Quality Assurance Deficiency, Unanticipated Environmental Interaction is assigned to the failure of the 525KV switchyard underhung insulator [EIIS:INS].

Analysis of the failed insulator revealed that a fracture of the multi-cone insulator occurred through the uppermost cone of the insulator, flush with the top of the second cone. Swelling of the cement over the second cone may have provided the axial tensile stress which apparently initiated the failure. Cement growth is a time and moisture dependent process. It appeared that an old radial crack in the top cone may have allowed moisture into the pocket of cement over the second cone. However, other diffusion based methods of moisture influx are also possible.

As a result of this insulator failure the following corrective actions were initiated:

a) Underhung insulators on offsite bus lines 2A and 2B were replaced.

b) The damaged Y phase of bus line 2B disconnect was removed and replaced with cable jumpers.

c) The X and Z phase of the 2B disconnect switch were closed and the operators were disabled so the switches cannot be opened.

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d) The Y phase of PCB disconnect switch 62R, which was damaged in the event, was repaired.

e) Two damaged insulators on PCB disconnect switch 62R were replaced.

f) A Nuclear Network bulletin discussing the insulator failure was issued on December 31, 1993.

It should be noted that bus line 2A could have been re-energized immediately following the opening of the Unit 2 generator breakers on December 27, 1993. However, the Senior Staff Engineer responsible for the secondary side of the plant decided that since the Unit 2 emergency D/Gs had successfully started and re-energized the Unit 2 4.16KV vital busses, a walkdown inspection of bus line 2A should be completed prior to returning the bus line to service. This walkdown was necessary to ensure the integrity of bus line 2A. The walkdown was completed, verifying no damage to bus line 2A. Bus line 2A was re-energized at 2342.

cause of Vendor Fabrication Deficiency is assigned to the failure of the Unit 2 T/G to runback following the loss of the 2B offsite bus line. This cause is assigned because jumpers on Digital Input Slave Module (DSIO1) which configure the module for either 24VDC or 125VDC operation were mispositioned by the vendor during the setup of the new Digital Electro-Hydraulic (DEH) system .

Investigation into the failure of the T/G runback revealed burned resistors on Digital Input Slave Module (DSIO1). One of the burned (failed) resistors prevented the runback signal from being recognized. The other failed resistor prevented the "Breaker Closed" input from responding.

The resistor failures were due to "Input Voltage Select" jumpers which were not properly positioned for 125VDC operation, as required. Instead, the jumpers were configured for 24VDC operation. This caused an excessive current through a current limiting resistor in each of the input circuits. The excessive current resulted in overheating of the resistors, and after a period of time, the failure of the resistors.

A search of the equipment history for the new DEH system, which was installed in 1987, indicated the jumpers had not been examined or changed since their original installation by the vendor. It was also determined that previous testing of the circuits would not have detected the problem, prior to the complete failure of the resistors. It is known

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that the Unit 2 T/G runback circuit was functional as recently as June 28, 1991, at approximately 0836. At that time an event occurred, which was documented in LER 370/91-05, that initiated an automatic runback to 56 percent load.

As a result of the Unit 2 T/G runback failure, the following corrective actions were initiated:

a) The failed DSI01 module was replaced with a new module which was properly configured for 125VDC operation. The new module was tested to verify that all inputs through the module operated and responded properly.

b) All other modules of this type on Unit 2 were verified to be properly configured for 125VDC operation.

c) All modules of this type on Unit 1 were visually verified to be properly configured for 125VDC operation.

d) Additional preventive maintenance checks (PMs) will be set up to ensure field digital inputs to the DEH system are tested and verified to operate each refueling outage.

e) The DEH system vendor, Bailey Instrument Company, was notified of this problem.

A cause of Inadequate Surveillance Program is assigned to the failure of valve 2SM-5 to fully close. The existing surveillance program for the MSIVs specified full stroke testing of the valves following modification or maintenance. In the past, these tests have been performed with the valves at ambient temperature. This was done to avoid potential inadvertent SIs upon reopening the MSIVs at operating temperature and pressure. This test method did not ensure the valves would meet the timing and stroke requirements at normal operating temperature.

A cause of Deficient Documentation, Incomplete Documentation is also assigned to the failure of valve 2SM-5 to fully close. An investigation into the failure of valve 2SM-5 to fully close revealed that inadequate clearance existed between the yoke rods and the yoke rod guides for the valve actuator. This inadequate clearance resulted in binding, which prevented valve 2SM-5 from fully closing.

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A search of the equipment history for valve 2SM-5 revealed that the clearances had been set in accordance with the applicable maintenance procedure, which instructed technicians to restore the clearances to the as found condition following maintenance.

At the request of Engineering personnel the vendor had provided a general manual update. This update included the correct clearances and installation instructions for the yoke rod guides. This information had not been incorporated into the vendor manual because it was still under review. Since the vendor manual is used as the reference document for maintenance procedure development, the clearances and installation instructions were not included in the maintenance procedure.

During the testing of the Unit 2 MSIVs in accordance with procedure PT/2/A/4255/03C, MSIV Functional Test And Closure Verification, on January 5, 1994, it was found that valve 2SM-7 did not fully seat because of an adjustment problem on a different set of guide pins from those which were adjusted at cold conditions.

These guide pins were adjusted on 2SM-7. These same pins were rechecked and adjusted where needed on the other Unit 2 MSIVs. All four Unit 2 MSIVs were then retested and verified to close properly.

The as found condition of valve 2SM-7 during testing on January 5, 1994, would have caused the internal pilot valve to be off its seat, although the main body of the valve would have been on its seat. The small flow path associated with the unseated pilot valve is consistent with the response of the 2A S/G after the SM isolation during the event.

To correct the problems with the maintenance and testing of MSIVs and the control of vendor information, the following corrective actions were initiated:

a) Unit 1 and 2 MSIV yoke rod guide clearances were measured and reset at normal operating temperature. This was completed by January 6, 1994.

b) A new periodic test procedure, PT/2/A/4255/03C, was written to verify full closure of the MSIVs at full temperature and SM pressure >/= 900 psig.

c) The Unit 2 MSIVs were initially stroke tested per procedure PT/2/A/4255/03C on January 5, 1994.

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d) The vendor manual for MSIVs will be revised to include yoke rod guide installation procedure and yoke rod to yoke rod guide clearances (Problem Investigation Process (PIP) 2-M93-1324).

e) The Unit 1 MSIVs will be stroke tested at operating temperature and pressure at the first opportunity.

f) A Nuclear Network bulletin discussing the MSIV failure was issued on December 31, 1993.

In addition to these actions, an evaluation was conducted to identify any needed short term procedure changes associated with safety related equipment, based on pending technical bulletins, vendor manual re-issues, etc. No items were identified which required attention prior to Unit 2 startup (PIP 2-M94-0025).

As a result of the SI and SM isolation following the loss of offsite power, a Project Team was formed, under the leadership of the MNS System Engineering Group. This team will develop planned actions that will reduce the probability of a SI following a loss of offsite power.

A cause of Inappropriate Action, Failure To Follow Procedure is assigned to the inadvertent failure to initially complete procedure RP/0/A/5700/10. This cause is assigned because the OPS Shift Supervisor did not ensure the required NRC 1 hour notification was completed in accordance with the procedure RP/0/A/5700/10.

Later in the event, on December 28, 1993, at approximately 0100, the Dedicated NRC Communicator in the TSC discovered that a copy of procedure RP/0/A/5700/10 had not been completed. The NRC Dedicated Communicator executed a procedure RP/0/A/5700/10 notification at approximately 0132.

As a result of the failure to complete procedure RP/0/A/5700/10 the following corrective actions were initiated:

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a) An immediate training package (Training Package 94-001) was issued by Operations which requires the Shifts to designate an SRO to ensure proper notifications to offsite agencies are performed. In addition, emphasis was placed on the timeliness and accuracy of the information provided to offsite agencies.

b) Procedure RP/0/A/5700/10, NRC Immediate Notification Requirements was revised to include approval by the Shift Supervisor/Emergency Coordinator prior to transmittal of information.

During this event the Technical Specification 3.4.9.1 cooldown rate of 100 degrees F per hour was exceeded. The cause of this excessive cooldown rate was the failure of valve 2SM-5 to fully close, resulting in excessive heat removal from the NC system via the 2B S/G. An Operability Evaluation was conducted and documented in PIP 2-M93-1341. This evaluation concluded that the integrity of the Unit 2 NC system piping, Reactor Vessel, and S/Gs were not challenged from a fatigue point of view and are operable.

As a result of the failure of 2SM-5 to fully close, S/G 2B was emptied. An Operability Evaluation for S/G 2B was conducted and documented in PIP 2-M93-1319. This evaluation concluded that the transient did not adversely effect the tube integrity of S/G 2B. The evaluation also determined that no tube inspections were necessary as a result of the transient.

During the event the PRT Rupture Disks relieved to prevent overpressurization of the PRT. An Operability Evaluation for the PRT was conducted and documented in PIP 2-M93-1323. This evaluation concluded the PRT Rupture Disks functioned as designed and that the PRT remained operable. Prior to restart both PRT Rupture Disks were replaced. Visual inspections of the PRT nozzle welds, steam deflector supports, mechanical snubbers and the first normally closed diaphragm valves off the PRT were conducted. No problems were identified.

Following relief of the PRT Rupture Disks, steam and water were released into Unit 2 Lower Containment. An Operability Evaluation to assess the environmental impact of the release was conducted and documented in PIP 2-M93-1321. In conjunction with this evaluation various equipment was inspected and no problems were identified due to moisture intrusion. The results of the evaluation and the inspections indicated no problems existed as a result of the event.

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An additional result of the relief of the PRT Rupture Disks was the opening of several Lower Ice Condenser Doors. An Operability Evaluation was conducted to ensure the Ice Condenser was operable following the PRT Rupture Disk event. This Operability Evaluation was documented in PIP 2-M93-1327. The evaluation concluded the Ice Condenser was operable based upon the completion of all applicable Technical Specification Surveillance Requirements. This included the weighing of ice baskets under work order 93093240.

During the event OPS C/R personnel requested IAE personnel to close valves 2SM-83, 89, 95, and 101. Actions taken by IAE personnel to air line jumper these valves closed actually resulted in the opening of valves. This problem was documented and thoroughly investigated in PIP 2-M93-1338.

A search of the Operating Experience Program (OEP) data base for reportable events occurring during the 24 months prior to this event was conducted. The search revealed no events attributed to Deficient Documentation, or an Inadequate Surveillance Program.

The search revealed one event attributed to a Possible Design, Manufacturing, Construction/Installation Deficiency, which was documented in LER 370/92-04. LER 370/92-04 specifically assigned a cause of Possible Installation Deficiency, while this event is assigned a cause of Possible Design Deficiency, due to an unanticipated environmental interaction. The root causes of the two events are different; therefore, the two events are not considered to be similar.

The search revealed one event attributed to a Vendor Fabrication Deficiency, which was documented in LER 369/93-01. While the two events share the same root cause, neither the equipment nor the vendor are the same.

The search revealed one event attributed to Inappropriate Action, Failure To Follow Procedure, which was documented in LER 369/92-07. While the two events involved the same group, the specific root causes are different. The event involved a failure to properly follow the correct procedure due to an interpretation of a procedure step. This event involved a failure to follow a procedure when one existed. The root causes are not the same; therefore, the two events are not considered to be similar.

This event is not considered to be recurring.

This event is Nuclear Plant Reliability Data System (NPRDS) reportable.

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There were no radiation exposures or uncontrolled releases of radioactive material as a result of this event.

CORRECTIVE ACTIONS:

Immediate:

1) Operations C/R personnel responded to the event in accordance with Unit 2 Emergency procedures.

2) Offsite power was restored to Unit 2 through the 2A bus line on December 27, 1993, at 2342.

3) Unit 2 was cooled down to Mode 5, Cold Shutdown for repairs.

Subsequent:

1) Site Management initiated a Recovery Team to manage recovery plans and implement corrective actions associated with the Unit 2 Loss Of Offsite Power.

2) Site Management activated a Significant Event Investigation Team to investigate the event.

3) Mechanical Maintenance (MM) and Engineering (ENG) personnel adjusted the yoke guide rods on valve 2SM-5 to allow the valve to fully close.

4) Mechanical Maintenance personnel measured yoke rod guide clearances for Unit 1 and 2 MSIVs at full operating temperature in accordance with procedure MP/0/A/7200/11, MSIV And Valve Actuator Corrective Maintenance.

5) Procedure PT/2/A/4255/03C was written to verify full closure of each MSIV at full temperature and steam line pressure >/= 900 psig.

6) Unit 2 MSIVs were stroke tested in accordance with procedure PT/2/A/4255/03C on January 5, 1994.

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7) In accordance with Minor Modification (MM) 5400, Power Delivery Department (PDD) personnel replaced the failed insulator and the other underhung insulators on 2B bus line and repaired PCB disconnect switch 62R.

8) In accordance with MM 5401, PDD personnel replaced underhung insulators on 2A bus line.

9) A visual inspection of Unit 1 bus lines was performed by PDD personnel to verify that insulators installed in the cantilevered position had been previously replaced with Lapp Catalog number J-51688 insulators. There are no underhung insulators in the Unit 1 (230KV) switchyard.

10) PCBs 61 and 62 were inspected and cycled by PDD personnel on December 30, 1993.

11) Instrument and Electrical personnel replaced the failed Digital Input Slave Module DSI01 and the T/G runback circuit was functionally verified under work order 93092661. All other similar modules on Unit 2 were examined to ensure correct jumper configuration. Unit 1 modules were also verified to have the correct jumper configuration.

12) Engineering personnel contacted the DEH system vendor, Bailey Instrument Company, and notified them of the problems with mispositioned jumpers.

13) An immediate training package (Training Package 94-001) was issued by Operations personnel which requires the OPS Shifts to designate an SRO to ensure proper notifications to offsite agencies are performed. In addition, emphasis was placed on the timeliness and accuracy of the information provided to offsite agencies.

14) Emergency Planning personnel revised procedure RP/0/A/5700/10, NRC Immediate Notification Requirements, to include approval by the Shift Supervisor/Emergency Coordinator prior to transmittal of information.

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15) Instrument and Electrical personnel were briefed on this event and the importance of attention to detail, along with the use of VTO drawings. Documentation of the briefing to IAE Supervision by the IAE Manager will be maintained in the IAE support area.

16) Engineering personnel red marked C/R and Shift Office Vital To Operation (VTO) drawings (flow diagrams and electrical one-lines) to reflect all changes resulting from each NSM. This included all extraneous information such as piping classification, cable number, etc. These drawings will be used for troubleshooting and communicating complete information among groups.

17) Engineering personnel performed an assessment of the current state of updates to safety related documents and procedures due to vendor information changes (PIP 1-M94-0025). No items were identified which needed to be considered prior to Unit 2 startup.

19) Testing of the Unit 1 runback circuitry was added to the trip list

20) A Nuclear Network bulletin discussing the insulator failure was issued on December 31, 1993.

21) A Nuclear Network bulletin discussing the MSIV failure was issued on December 31, 1993.

22) Engineering personnel revised the vendor manual for MSIVs to include yoke rod guide installation procedure and yoke rod to yoke rod guide clearances.

Planned:

1) Engineering personnel will setup PMs to ensure all DEH runback circuit field inputs are functionally tested each refueling outage.

2) The Unit 1 MSIVs will be stroke tested at system operating temperature and pressure as soon as practical.

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3) As a result of the SI and SM isolation following the loss of offsite power, a Project Team was formed, under the leadership of the MNS System Engineering Group. This team will develop planned actions that will reduce the probability of a SI following a loss of offsite power.

SAFETY ANALYSIS:

The event which occurred, a loss of offsite power to one unit, coincident with a failed Main Steam Isolation Valve, is bounded by events described in chapter 15 of the Final Safety Analysis Report (FSAR). Specifically, it is bounded by the Complete Loss of Reactor Coolant Flow and the Steam Line Break events.

Following the loss of the 2B bus line, the 6.9kV switchgear, which is normally supplied from this source, successfully completed an automatic transfer to the 2A bus line. However, the failure of the Unit 2 T/G to runback caused the 2A bus line to subsequently trip due to an overcurrent condition. A Reactor Trip occurred, as designed, prior to reaching any of the established Reactor Core safety limits. The main generator tripped, causing a complete loss of Unit 2 auxiliary power.

The flywheel of the NC pumps performed its design function and extended the coast down time of these pumps and thus established the proper conditions to initiate natural circulation flow through the Reactor core. The natural circulation flow, which is maintained due to density changes in the NC system, allowed heat to be removed from the Reactor core and transferred to the S/Gs as designed. The operation of the SM Line PORVs allowed the excess heat to be dissipated to the environment, as designed, from the secondary side of the S/Gs. With the automatic initiation of Auxiliary Feedwater, which initially supplied several hundred gallons per minute of feedwater flow to each S/G, Unit 2 was in a condition to maintain heat removal from the NC system indefinitely.

During this event, electrical power was supplied to the safety related equipment by emergency D/Gs. These D/Gs started automatically due to the loss of offsite power, and supplied power to the 4.16kV busses until offsite power was restored. The D/Gs operated as designed through out this event and electrical power for the safety related equipment was not a concern during the event.

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This loss of power event was complicated by an excessive cooldown which has been attributed to the large amount of Auxiliary Feedwater flow and to various steam leakage paths. This cooldown led to the initiation of Safety Injection due to low Pressurizer pressure. The Safety Injection signal initiates system realignments and actuation to provide a source of make up water to the NC system. The Safety Injection systems functioned as designec in this event. The excessive cooldown also resulted in a signal to isolate the SM lines. This isolation was not completely successful due to the failure of 2SM-5 to completely close. With this valve not fully closed the cooldown continued until the 2B S/G was emptied and CA system flow was throttled. The rate at which the NC system was cooling down was slowed by actions taken from the C/R to limit the effect of the transient.

The Technical Support Center, which was activated as a precaution during the event, took an active role to ensure that once the 2B S/G was empty, no water was reintroduced. This measure prevented the creation of thermal stress in the 2B S/G, which could have led to damage of the S/G tubes. This event did not result in any leakage of primary coolant (NC system) through 2B S/G tubes.

The overall response of the plant, from a safety point of view, was satisfactory through out the event. There were equipment failures which initiated the transient and failures which contributed to the severity of the event. However, at no time during the event was there a challenge to Reactor Safety and the safety system response was sufficient to prevent degradation of the event to a more serious level. During the event, plant parameters did not exceed any safety limit as defined by Technical Specifications.

All radiological releases associated with the release of steam during the event were well within acceptable levels and all NC system releases were maintained inside the primary containment structure. There were no radiological consequences associated with the event.

This event was not significant with regard to the health and safety of the public.

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ADDITIONAL INFORMATION:

SEQUENCE OF EVENTS

Key to Data Sources:

ER	Events Recorder, Time to Milliseconds
AS	Operator Aid Computer (OAC) Alarm Summary, Time to the second
TM	OAC Transient Monitor Data Plots, Time to seconds
CRI	Control Room Indication
SRO	Senior Reactor Operator (SRO) Logbook Entry Times
BE	Best Estimate based on Engineering/Operational Judgment
APD	All Points Data Base - OAC Data Archived Every 5 minutes

12/27/1993

22:06	Received loss of BL2B, observed T/G not running back (SRO)
22:06:31.588	Generator Breaker 2B open (ER)
22:06:31.757	PCB 61 tripped (B Buss) (ER)
22:06:32.025	PCB 62 tripped (B Buss) (ER)
22:07:00	NIS N41 Power - 100.079% (TM)
22:07:00.161	PCB 58 tripped (A Buss) (ER)
22:07:00.179	Unit 2 OPC Operation (ER)
22:07:00.292	PCB 59 tripped (A Buss) (ER)
22:07:00.343	Unit in Full Load Rejection (ER)
22:07:01	All Turb. Governor Valves, Intercept Valves, Closed. SB-9 & 21 (Steam Dumps) started to open (AS)
22:07:07	Pzr PORVs NC-34, NC-36, NC-32 open (AS)
22:07:07.992	NIS Hi Flux Rate Power Range Rx-Trip (ER/BE)
22:07:08.079	Reactor Trip Breaker A Open (ER)
22:07:08.095	Reactor Trip Breaker B Open (ER)
22:07:08.221	Turbine Trip (ER)
22:07:08.325	Generator Breaker 2A Open (ER/BE)
22:07:08.398 - .505	2ETA, 2ETB Undervoltage alarms (ER)

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22:07:08.511	Train A Blackout logic initiated (ER)
22:07:08.515	Train B Blackout logic initiated (ER)
22:07:08.547	Starting Diesel Generators 2A, 2B (ER)
22:07:09	Pzr PORVs NC-34, NC-36, NC-32 closed (AS)
22:07:13.125	Manual Reactor Trip train A (ER)
22:07:13.149	Manual Reactor Trip train B (ER)
22:07:16.813	2A Blackout logic actuated (ER)
22:07:16.887	2ETA Load Shed (ER)
22:07:16.906	D/G 2B Running (ER)
22:07:16.909	2B Blackout Logic Actuated (ER)
22:07.[illegible].992	2ETB Load Shed (ER)
22:07:17.279	D/C 2A Running (ER)
22:07:18.018	D/G 2A Breaker Closed (ER)
22:07:18.072	D/G 2B Breaker Closed (ER)
22:07:25	2A & 2B FWPT Tripped (AS)
22:07:29	TD CA flow starts and reaches ~210 gpm per S/G
22:07:44	A and B CA Pumps Start (AS)
22:07:50	CA Pumps A&B On (AS/TM)
22:07:50	SA-49 Opened (AS)
22:08:37	SA-48 Opened (AS)
22:10:04	3 PORVs (SV-1, 13, 19) closed (AS) 2 Code Safety Relief valves (SV-2, 14) closed (AS)
22:14	Received SI on "LO PZR PRESS" (SRO)
22:14:04.056	Pressurizer low pressure safety injection (ER)
22:14:05.759	Steamline B lo pressure safety injection (ER)
22:14:11	ND pumps A and B on (AS)
22:14:11	NI pumps A and B on (AS)
22:14:11	SM-1, SM-3 and SM-7 Closed (AS)
22:14:14	NI-9 & NI-10 (BIT dischg. Isol.) (AS)
22:14:35.912	Steamline C lo pressure safety injection (ER)
22:15	Ice Condenser temperature increase (CRI/BE)
22:15:07.819	Steamline A lo pressure safety injection (ER)
22:15:34.075	Steamline D lo pressure safety injection (ER)
22:22	Declared NOUE "Notification of Unusual Event" (SRO)
22:23:17	SA-48 Closed (AS)
22:23:20	CA flow stopped to all four S/G's (TM)

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22:24:29	SM-15 Indicated Closing (AS)
22:26:33	CA flow started for S/G B (pegged high off (TM) scale)
22:28 - 22:49	Pzr PORVs cycled about once per min. (AS)/(TM)
22:29:57	CA flow started for S/G A (TM)
22:32:00	CA flow stopped for S/G A (TM)
22:36:29	CA flow stopped for S/G B (TM)
22:36:45	CA flow started for S/G A (TM)
22:40:21	SM-15 Closed (AS)
22:41:09	ND pump B off (AS)
22:41:10	ND pump A off (AS)
22:41:14	NI pumps A and B off (AS)-
22:43	Max. lower containment ambient (AS)
22:45:49.939	S/G B lo level reactor trip (ER)
22:49:52.850	Pzr Safety Injection Reactor Trip signal (ER)
22:51:44.186	Pzr Safety Injection Reactor Trip signal (ER)
22:56:36.247	Unit 2 Condenser vacuum low trip (ER)
23:01:35	PRT Pressure -50.3 psig (AS)
23:06:05.573	Pzr Safety Injection Reactor Trip signal (ER)
23:23:19	PRT Pressure -52.3 psig (AS)
23:26:44	PORV NC-36 Open (AS)
23:26:49	PRT Pressure - 7.6 psig, (AS/BE)
23:27:23	PORV NC-36 Closed (AS)
23:30 (Approx.)	Several Ice Condenser Temperatures Increasing (CRI/BE)
23:42	Re-energized BL2A (SRO)
23:42:03	Offsite power restored (ER)

<u>12/28/93</u>

00:18	2ETB Re-energized from Offsite (SRO)
00:32	2ETA Re-energized from Offsite (SRO)
01:37:18	Reactor Coolant Pump A on (AS)
07:37	SM pressure equalized in all four (TSC)
12:55	Secured from Notification of Unusual Event (SRO)

LER No. 373/93-015
LaSalle Unit 1

LICENSEE EVENT REPORT (LER)

Form Rev 2.0

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Title (4)

Unit 1 Scram and Loss of Off-Site Power Due to Bus Duct Water Intrusion

Event Date (5)			LER Number (6)			Report Date (7)			Other Facilities Involved (8)	
Month	Day	Year	Year	Sequential Number	Revision Number	Month	Day	Year	Facility Names	Docket Number(s)
									LaSalle Unit 2	0 5 0 0 0 3 7 4
0 9	1 4	9 3	9 3	— 0 1 5 —	0 0	1 0	1 2	9 3		0 5 0 0 0

OPERATING MODE (9)	1
POWER LEVEL (10)	1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)

___ 20.402(b)	___ 20.405(c)	X 50.73(a)(2)(iv)	___ 73.71(b)
___ 20.405(a)(1)(i)	___ 50.36(c)(1)	___ 50.73(a)(2)(v)	___ 73.71(c)
___ 20.405(a)(1)(ii)	___ 50.36(c)(2)	___ 50.73(a)(2)(vii)	___ Other (Specify in Abstract below and in Text)
___ 20.405(a)(1)(iii)	X 50.73(a)(2)(i)	___ 50.73(a)(2)(viii)(A)	
___ 20.405(a)(1)(iv)	___ 50.73(a)(2)(ii)	___ 50.73(a)(2)(viii)(B)	
___ 20.405(a)(1)(v)	___ 50.73(a)(2)(iii)	___ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER	
	AREA CODE	
Ron Ragan, System Engineer Supervisor, Extension 2243	8 1 5	3 5 7 - 6 7 6 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	E L	X F M R	G 0 8 2	Y	X	A D	V	L 2 0 0	Y
X	E F	M O	G 0 8 3	Y					

SUPPLEMENTAL REPORT EXPECTED (14)

		Expected Submission Date (15)	Month	Day	Year
___ Yes (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single-space typewritten lines) (16)

On September 14, 1993 Unit 1 was in Operational Condition 1 (RUN) at 100% power. At 1147 hours the System Auxiliary Transformer (SAT) experienced a differential current auto-trip due to water intrusion in the 4.1 kV ductwork and a fast transfer of loads to the Unit Auxiliary Transformer (UAT) occurred. During the bus transient, the 4.1 kV bus experienced lower than normal voltage. This low voltage condition caused the Feedwater Control System for the 1B Turbine Driven Reactor Feed Pump (TDRFP) to lock up. This caused speed and flow to decrease to zero. The 1A TDRFP was unable to make up the loss in flow, and the reactor scrammed on low reactor water level. Following the Scram the UAT was lost when the Generator separated from the Grid. This resulted in a loss of offsite power. All three diesel generators auto started and picked up the busses.

Reactor water level was restored and controlled initially by Reactor Core Isolation Cooling (RCIC), and later by Low Pressure Core Spray (LPCS). Reactor pressure was controlled by RCIC and the Safety Relief Valves (SRV). Due to a failure of the 1B Reactor Protection System (RPS) Motor Generator isolations were unable to be recovered initially. The Unit was later placed in Cold Shutdown.

This event is being reported pursuant to:

1. 10CFR50.73(a)(2)(i)(B) due to not meeting the limiting condition of operation (LCO) of Technical Specification 3.4.4.
2. 10CFR50.73(a)(2)(i)(C) due to deviating from plants Technical Specifications per 50.54(x) when LaSalle General Plant Abnormal Procedures (LGA) LGA-CM-01 and LGA-VP-01 were invoked.
3. 10CFR50.73(a)(2)(iv) due to the actuation of an Engineered Safety Feature System (ESF) and the automatic actuation of RPS.

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PLANT AND SYSTEM IDENTIFICATION:

General Electric - Boiling Water Reactor

Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

A. CONDITION PRIOR TO EVENT

Unit(s): 1 Event Date: 9/14/93 Event Time: 1147 Hours

Reactor Mode(s): 1 Mode(s) Name: Run Power Level(s): 100

B. DESCRIPTION OF EVENT

On September 14, 1993 Unit 1 was in Operational condition 1 (Run) at 100% power. At 11:47 hours a fault occurred on the Unit 1 System Auxiliary Transformer (SAT, MP) [EL]. An automatic fast transfer of loads from the SAT to the Unit Auxiliary Transformer (UAT) occurred, as designed. During the fault and bus transfer several events occurred:

(1) The 1A and 1B Turbine Driven Reactor Feed Pumps (TDRFP, FW) [SJ] were on line. Control power was momentarily lost to the Feedwater Control System (FW) [JK]. The 1B TDRFP lost its control signal causing its speed (and flow) to decrease. The 1A TDRFP flow increased but was unable to increase enough to maintain reactor water level above the low level scram setpoint of 12.5 inches. A Unit 1 scram occurred at 19 seconds after the loss of the SAT due to low reactor water level. After the scram, reactor water level was rapidly recovered, resulting in a high water level trip (55.5 inches) of the TDRFP's and the Main Turbine resulting in a Main Generator (TG) [TB] trip on reverse power at 11:49.

(2) The Division 3 D[illegible] Generator (DG) [EK] started as designed on undervoltage and loaded onto its bus. Division 3 does not have a power feed from the UAT.

(3) The Reactor Building Ventilation Dampers (VR) [VA] closed as well as some Primary Containment (PC)[JM] Isolation Valves as expected. A momentary loss of voltage will cause this to occur.

(4) The Unit 1 Station Air (SA) [LF] Compressor tripped as expected. This was also due to momentary drop in control power voltage.

(5) Reactor Water Cleanup (RWCU, RT) [CE] tripped due to isolation valve closure. This was caused by momentary drop in instrument power voltage.

See Attachment A for a sequence of events.

The SAT supplies power to the station from the grid and the UAT supplies power to the station from the Main Generator. With the loss of the SAT due to the fault and the Main Generator trip, Unit 1 was in a Loss of Off-site Power (LOOP) condition. The other two emergency Diesel Generators for Unit 1 auto-started on undervoltage and loaded onto their respective busses. This returned power to Unit 1 emergency busses. Additionally, the required second offsite power source to Unit 1 was available from the Unit 2 cross-tie breakers and was energized at 12:57 for Division 2 and 13:04 for Division 1 to

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B. DESCRIPTION OF EVENT CONTINUED

allow unloading and securing the Diesel Generators. Additional 4.1 kV busses which could be powered from the DG or Unit 2 were energized as needed during the period when the UAT and SAT were de-energized.

LaSalle SAT and UAT provide 4.1 kV and 6.9 kV for station loads. The Emergency DG and the other Unit only supply 4.1 kV power. Therefore, the 6.9 kV busses remained de-energized. The 6.9 kV busses supply power to balance-of-plant equipment. Unit 2 was in a refueling outage at the time and receiving power from its SAT which was unaffected by this transient.

Upon the loss of the UAT additional events occurred:

(1) The Reactor Protection System (RPS, RP) [EF] and the Primary Containment Isolation System (PCIS, PC) [NH] logic initiated due to the loss of RPS bus power. The major effects were: Main Steam Isolation Valves (MSIV, MS) [SB] closure which removed the Main Condenser as the heat sink, a Primary Containment chiller isolation, a loss of low pressure Drywell Instrument Nitrogen (IN) [LE] and a Standby Gas Treatment (SBGT, VG) [BH] initiation for both trains. The RPS busses were re-energized from their respective Motor Generator (MG) sets to enable isolation recovery, but at 12:17 (approximately 30 minutes into the event), the 1B RPS MG set tripped. The alternate RPS power supply is from a 6.9 kV bus which cannot be fed from the DG or Unit 2. This resulted in the inability to easily recover from the isolation. Subsequently, at 19:07 a temporary power feed was installed for the B RPS bus which enabled isolation recovery.

(2) The Unit 2 Station Air Compressor tripped due to the loss of Unit 1 Turbine Building Closed Cooling Water (TBCCW, WT) [KB]. Unit 1 TBCCW was cross-tied supplying cooling water to the Unit 2 Station Air Compressor. Unit 1 TBCCW Pumps are powered from electrical switchgear which are supplied from 6.9 kV busses. The Unit 1 and Unit 0 Station Air Compressors became unavailable because their control power is supplied by Unit 1 6.9 kV busses.

This caused a low Instrument Air (IA) pressure condition on both Units and allowed air operated valves to go to their failed positions. The Unit 2 Scram Discharge Volume (SDV) vents and drains closed causing a Scram signal to be generated on Unit 2. Unit 2 was in the refuel mode with all control rods fully inserted and the reactor core partially unloaded prior to the event. IA was restored at approximately 14:04.

(3) The Unit 1 and 2 Fuel Pool Cooling Systems (FC) [DA] were lost due to a loss of filter/demin control power which is supplied from a Unit 1 6.9 kV bus. A temporary power feed was established and Fuel Pool Cooling was restored at 14:54. An increase in pool temperature of less than 5 degrees occurred on Unit 2. The Unit 1 Fuel Pool did not have any fuel in it at the time.

As a conservative measure and to ensure that all available help needed was assembled, the Station Manager declared an Emergency Classification Alert condition. The proper notifications to the State and the NRC were made, as required.

Safety Relief Valves (SRV, MS) [SB] were used to control reactor pressure and Reactor Core Isolation Cooling (RCIC, RI) [BN] was used for level and pressure control. The 'K' SRV opened first, however it is not in the first group of lowest pressure SRVs. Due to the loss of the low pressure Drywell Instrument nitrogen, several Automatic Depressurization System (ADS, [illegible]) [SB] SRVs were operated using the installed backup High pressure bottled nitrogen supply. At 17:11 Low Pressure Core spray (LPCS, LP) [BM] was started for reactor water level control. At this time reactor pressure had decreased to the point where LPCS could inject.

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B. DESCRIPTION OF EVENT CONTINUED

Residual Heat Removal (RHR, RH) [BO] Shutdown Cooling was established at 04:59 on September 15, 1993 and Unit 1 achieved Cold Shutdown at 11:50. At 15:15, the UAT was re-energized and at 16:56, all busses were re-energized by backfeeding through the UAT. The Emergency Plan "Alert" classification was terminated at 16:48.

Other component failures, indication problems, or items of note that occurred during the transient are:

(1) 'E' SRV failed to fully open. 'D' SRV would not open. Other SRVs had position indication problems.

(2) The RCIC and LPCS Injection Check Valves failed to indicate fully closed after injection was secured.

(3) Reactor coolant samples required due to the loss of the Continuous Conductivity Monitor were not able to be taken within the required 4 hours per Technical Specification 4.4.4.c.1. The sample line for both methods of reactor water sampling was isolated due to the loss of the B RPS bus. These sample lines are used for both the continuous monitor and the grab sample. Technical Specification 4.4.4.c.1 requires that a grab sample be taken within 4 hours of the loss of the continuous monitor. The continuous monitor was lost at 11:49 and a sample was taken at 20:00 which exceeded the 4 hour limit. Sample results showed no fuel failure indications.

(4) Reactor coolant samples required for a 15% power change per Technical Specification 3.4.5 Action c were not able to be taken due to the loss of sample points. The Unit entered Hot Shutdown immediately following the Scram and the MSIV closed on the PCIS isolation. This met the requirements for Technical Specification 3.4.5 action a.

(5) Jumpers and lifted leads were used to bypass PC isolation signals as required per LaSalle General Plant Abnormal (LGA) Emergency Operating Procedures (EOP). The installation of these jumpers and lifted leads required, by procedure, invoking 10CFR50.54(x).

This event is being reported pursuant to:

1. 10CFR50.73(a)(2)(i)(B) due to not meeting the limiting condition of operation (LCO) of Technical Specification 3.4.4.
2. 10CFR50.73(a)(2)(i)(C) due to deviating from plants Technical Specifications per 50.54(x) when LaSalle General Plant Abnormal Procedures (LGA) LGA-CM-01 and LGA-VP-01 were invoked.
3. 10CFR50.73(a)(2)(iv) due to the actuation of an Engineered Safety Feature System (ESF) and the automatic actuation of RPS.

C. APPARENT CAUSE OF EVENT

The actual reactor Scram on Unit 1 was caused by low (12.5") reactor water level due to the loss of the 1B TDRFP. The individual failures that led to the loss of the TDRFP and the reactor scram, along with failures that occurred after the scram, are discussed individually below.

Loss of the SAT: The Unit 1 SAT auto-tripped on differential current. This was a result of water inleakage into the bus duct through degraded ductwork joint seals. This leakage [illegible] vertical ductwork run to a surge suppressor compartment in which a sufficient quantity of water shorted

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C. APPARENT CAUSE OF EVENT CONTINUED

the bus bars. An inspection revealed water marks and corrosion which indicated that the inleakage had been occurring over an extended period of time. The root cause of the bus bar short has been attributed to inadequate preventative maintenance on the ductwork seals. A contributing factor was a design which did not include low point drains in the vertical duct run.

Loss of 1B TDRFP: Immediately following the SAT fault, voltage on busses fed from the 4.1 kV side of the SAT experienced a rapid and significant decrease. For 120 Vac equipment, voltage may have been reduced to less than 72 Vac and remained degraded for a period of at least 200 msec. Based on testing performed after the event, this voltage level would initiate a decrease in the Electric Automatic Positioner (EAP) position. The EAP Controller raises or lowers turbine speed depending on the deviation between the desired speed from reactor water level control logic and actual speed. Therefore, the EAP position continued to decrease to try to zero the deviation until the lockout of the TDRFP occurred. Since the 1B TDRFP loss of signal lockout occurs at a relatively low supply voltage, the lockout is not expected to have occurred until near the end of the 200 msec time interval.

The decrease in EAP position resulted in a reduction in the 1B TDRFP speed and flow. Based on pump head/flow curves and computer data from the time immediately prior to and after the 1B TDRFP flow reduction, an EAP induced speed reduction of the 1B TDRFP of at least 1300 rpm was needed for flow to drop to zero. This amount of speed reduction is considered reasonable given the amount of EAP motion noted during testing.

Loss of the 1B RPS MG set: The 1B RPS MG set lost power following the main generator trip. It was restarted without problems and subsequently tripped due to a motor fault 30 minutes later. The motor winding was found to have a heavy layer of dirt on both ends of the winding. The winding was found to have experienced a turn to turn short at the first coil of a phase group. The most probable cause of this failure is a current spike through the motor winding caused by a transient or switching action due to interruption of power. The motor windings were also degraded from the abrasive action of the dirt on the winding insulation.

Safety Relief Valves (SRV):

1. 'K' SRV opened prior to 'S' and 'U' which have lower setpoints. 'S' and 'U' setpoints are 1076 psig with allowable tolerances of 1069 to 1099 psig. 'K' setpoint is 1096 psig with allowable tolerances of 1089 to 1119 psig. 'K' setpoint was found at 1088 psig, 1 psig out of tolerance, but within the range to operate before 'S' and 'U'.

2. 'D' SRV failed to open. The loss of power event resulted in a loss of low pressure drywell instrument nitrogen to the SRV accumulators, and 'D' SRV actuation was not required for over 2 hours after the loss of nitrogen. This was considered sufficient time for the accumulator to have bled down through the actuator block gasket leaks which were found. The ADS Accumulator was not affected. This non-safety related accumulator was not previously tested. The leaks were of sufficient quantity to prevent operation of this valve as the event occurred.

3. 'E' SRV showed dual indication when cycled from the Control Room. The valve stroke was determined to be 0.700", outside the acceptable value of 1". The spindle nut was found not tightened down properly with the load plate. This prevented the disk from going full open when stroked by the actuator.

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C. APPARENT CAUSE OF EVENT CONTINUED

4. The 'C' and 'U' SRV position indication developed problems late in the event. It was determined that the valves did stroke full open, but due to the number of times these valves were cycled, the position indication became mis-calibrated.

Reactor Recirculation (RR) [AD] Pump Suction Valve (1B33-F023A): This valve failed to fully close when given a close signal from the Control Room. The valve was then reopened and closed normally when given a second close signal. Testing revealed that the 1B33-F023A problem was related to either torque switch or seal-in contacts, or actuator lubrication. It is believed that the valve may have experienced a minor internal loading problem.

RCIC and LPCS Check Valve Position Indication Problems:

1. The LPCS Check Valve (1E21-F006) did not indicate full closed following shut down of the LPCS System. LPCS was used for vessel level control following the scram. The check valve was found in the full closed position, but the closed limit switch cam was loose, due to a stripped setscrew, resulting in improper position indication.

2. The RCIC Check Valve (1E51-F065) did not indicate full closed following the shut down of the RCIC System. The check valve was found in the partially open position as shown by the local position indication. The valve was taken full closed by rotating the external limit switch cam by hand. There was no excessive binding or internal interference preventing disc movement. The check valve is the upstream member of a pair of series check valves in the injection line. It has been previously identified and accepted that in this design, the second of the two check valves may receive insufficient differential pressure (dp) to close once the first valve has seated. Follow-up has shown that the valve easily closes by hand and would have closed if subjacted to a dp. Further review of the events identified that the other check valve (1E51-F066), experienced an indication problem during the event. This problem is a loose limit switch cam caused by the design of the disk.

Safety Parameter Display System (SPDS) Failure:

During the Alert, the SPDS monitor on the unit 1 Reactor Operator Desk as well as the SPDS Monitor above Control Room Panel 1H13-P603 failed. The failure was noted early during the event, though the precise time cannot be established. The SPDS monitors were available in the Unit 2 Control Room and in the Technical Support Center at all times. Other monitors in the Control Room never lost their ability to display data. This verified that the Process Computer and other monitors in the Control Room had not failed. Also, it was verified that the UPS power to the monitors in the Control Room had not failed during the event.

The SPDS Monitor above Control Room Panel 1H13-P603 was powered from Remote Lighting Cabinet (RLC) 12. A field walkdown to determine the power source of the SPDS Monitor on the Unit 1 Reactor Operator Desk, determined that it was also being powered from an RLC circuit, though the exact RLC circuit was not verified.

All RLC circuits are powered from non-safety related busses. During the Loss of Off-site Power, the non-safety busses on Unit 1 would have load shed to allow the DGs to come online. The non-safety busses were not restored until the busses were manually restored. Control Room Personnel noted that the SPDS Monitors were operating as usual a few hours into the event.

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D. SAFETY ANALYSIS OF EVENT

Reactor water level dropped to below the scram point 12.5" (level 3) but did not challenge the High Pressure Core Spray (HPCS)/RCIC initiation point of -50 inches (level 2). Reactor pressure increased to the automatic opening setpoint of an SRV in the relief mode (approximately 1070 psig), and pressure was controlled using RCIC and manually operating SRV's. This is the normal method of level/pressure control following a scram with a MSIV closure condition. The suppression pool temperature increased to approximately 124 degrees and level to approximately +3.5 feet due to the steam discharge into the Suppression Pool from RCIC and SRV's.

A LOOP due to a SAT fault is described in Updated Final Safety Analysis Review (UFSAR) section 15.2.6 as a moderate frequency event. This event did not significantly differ from that described in the UFSAR.

A Confirmatory Action Letter (CAL) was issued after this event.

E. CORRECTIVE ACTIONS

On-site review 93-048 was initiated and approved to address issues related to this event. A summary of the corrective actions is provided below. The immediate actions taken after the scram are identified in the Description of Events.

Loss of the SAT: Oil samples of the SAT were taken for analysis to determine if damage occurred to the SAT. A meggar of the transformer and a transformer turns ratio test was performed. The 4.1 kV bus connections were disassembled, cleaned, and reassembled. The 6.9 kV bus bars were wiped down and connections retorqued. Both 4.1 kV and 6.9 kV bus duct enclosures were resealed and the bottom cover filter drain/vents replaced. Holes were drilled in the bus duct channel supports to prevent the buildup of water above the sealed connections to the internal insulator supports. The transformer low side surge suppressors of both the 4.1 kV and 6.9 kV were permanently removed. Inspection of the duct sealing tape was completed. Procedures LEP-AP-101/201 for Transformer Bus Duct Inspections will be reviewed for clarifications and enhancements. Action Item Record (AIR) 373-240-93-04828 will track this.

Loss of 1B TDRFP: Testing revealed that the TDRFP's operated as designed as a result of the sudden voltage transient. Dahl (Manufacturer) EAP testing on the 1B TDRFP determined that a low voltage level would increase the EAP position. The new Lovejoy TDRFP Control System Modification for Unit 1, which is planned for installation during L1R06, will be evaluated for the impact of the same voltage transient. AIR 373-240-93-04801 will track this evaluation. Unit 2 TDRFP Control System is powered by an UPS and would not have been susceptible to this type of event.

1B RPS MG set: The 1B RPS MG motor was sent out for refurbishing and was replaced. The 1A motor was also sent out for cleaning and revarnishing of the windings. AIR 373-240-93-04808 was issued to revise the cleaning frequency and method of cleaning. Unit 2 RPS MG sets 2A and 2B were also inspected and found to be in an acceptable condition.

SRVs: One of 'K' SRV pressure switches was recalibrated within its tolerance. The 3 other 'K' SRV pressure switches were found within tolerance. This single drift out-of-tolerance condition is acceptable. 'D' SRV air leaks were repaired and the valve was successfully stroked. The other SRVs were tested satisfactorily. A periodic leak test of the non-ADS SRV accumulators will be performed as preventive maintenance. AIR 373-240-93-04805 will track this action.

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E. CORRECTIVE ACTIONS CONTINUED

The 'U' SRV Lift Indicating Switch Assembly (LISA) was replaced, and both the 'U' and 'C' SRV LISAs were recalibrated and restroked successfully. The loose spindle nut on 'E' SRV was tightened to make contact with the loading plate and backed off one turn per vendor procedure. The other SRVs were inspected and found to be acceptable. The method of tightening the spindle nuts was revised to ensure the loading plate was secured prior to locking the spindle nut in place. AIR 373-240-93-04802 will track this item.

1B33-F023A: A current signature trace was performed and showed no new signs of valve degradation. The torque switch, which was found dirty and tarnished, was cleaned and raised to its maximum allowable setting. In addition, the valve stem and anti-rotation device were lubricated. A procedure deficiency was written to change the "preferred" valve to shut during Shutdown Cooling (SDC) operation from the 1(2)B33-F023A/B suction valve to the 1(2)B33-F067A/B discharge valve. 1B33-F023A internals will be inspected for wear or damage during L1R06. AIR 373-240-93-04829 will track this inspection.

RCIC and LPCS check valve position indication: Due to the problems with the cam set screws, all RCIC, RHR, and Emergency Core Cooling System (ECCS) Check Valves Cams were inspected. This inspection included replacing all the limit switch set screws, cleaning the internal threads (or drilling a new tap hole if the hole was stripped), and cleaning of the cam shaft with an emery cloth prior to tightening the new setscrews. AIR 373-240-93-04612 includes the inspection of both Units.

SPDS: The SPDS Monitor above Control Room Panel 1H13-P603 was rewired to be powered off an UPS Power Source. The SPDS Monitor at the Unit 1 Reactor Operators Desk was rewired and is being powered from an UPS power source. Unit 2 will be rewired prior to Unit 2 Start-Up under Modification P01-0-90-008.

Additionally, the Fuel Pool Cooling control design will be reviewed and the corrective actions will be reviewed for applicability to Unit 2. AIR 373-240-93-04815 will track this review.

F. PREVIOUS EVENTS

LER NUMBER	TITLE
373/87-014-00	Reactor Scram Due to Transformer 141 Differential Current Trip
374/90-007-01	Loss of System Auxiliary Transformer Caused by a Fire Protection Deluge of the Transformer Due to a Short in the Deluge Manual Pull Station Switch
374/92-012-00	Reactor Scram Due to a Main Turbine Trip Caused by a Thrust Bearing Wear Detector Signal
373/82-007-03L-0	RCIC Testable Check Valve Indication Failure
373/91-006-00	Reactor Scram On Low Reactor Vessel Level Due to Loss of "A" Turbine Driven Reactor Feedwater Pump Caused by Control Valve Closure

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G. COMPONENT FAILURE DATA

MANUFACTURER	NOMENCLATURE	MODEL NUMBER	MFG PART NUMBER
General Electric	System Auxiliary Transformer	N/A	Serial #K-547285
General Electric	Motor	5K326AN260BP	N/A
Limitorque	Valve	SMB-0	N/A

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ATTACHMENT A

9/14/93

11:47 33 Unit 1 System Aux Transformer (SAT) lockout(trip) due to low (4160 Kv) bus duct fault. This causes voltage drop on transformer output.

Fast transfer of busses 152, 142Y, 142X, and 141Y from the SAT to the Unit Aux Transformer (UAT) occurs as expected.

0A diesel fire pump (DFP) starts due to transformer deluge.

B Reactor Recirc Flow Control Hydraulic Power Unit (HPU) isolation valves close due to momentary power loss.

U1 Service Air Compressor (SAC) trips due to momentary loss of control power.

Division 3(HPCS) SWGR 143 losses power. There is no UAT feed to Division 3.

Reactor Building Ventilation (VR) secondary containment dampers close.

37 Division 3 Diesel Generator (DG) running due to Bus 143 undervoltage

41 Reactor low level (level 4, +31.5") alarm

42 RWCU trips

44 Division 3 bus 143 energized by the Division 3 (1B) DG

52 Reactor SCRAM low water level (level 3, +12.5"). This is an LGA-01 (EOP) Entry Condition.

Reactor recirc (RR) pumps downshift to slow speed at reactor level 3 as designed.

11:48 25 Operator closes 1B Turbine Driven Reactor Feed Pump 1B discharge valve, 1FW010B as expected post scram action.

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ATTACHMENT A CONTINUED

	46	Reactor level increases above Level 3.
	50	Operator closes 1A Turbine Driven Reactor Feed Pump 1A discharge valve, 1FW010A as an expected post scram action.
		Motor Driven Reactor Feedwater Pump (MDRFP) auto starts as expected.
	56	Reactor level increases above Level 4.
11:49	00	Reactor level increases above high level alarm (level 7, +41.5")
	04	Reactor level increases above high level main turbine and feedwater pump trip point (Level 8, +55.5")
	05	Sequence of Events Recorder memory FULL. This occurs when a large number of alarms are received in a short period of time.
	06	Main Turbine trips due to high reactor level 8.
		MDRFP trips due to high reactor level 8.
	12	Main Generator trips due to reverse power as expected.
		All busses lose power due to loss of the Unit Auxiliary Transformer (UAT) which is powered directly from the main generator.
		RPS busses lose power due to loss of power to MG set.
		0 Diesel Generator ENERGIZES Bus 141Y, 1A Diesel Generator ENERGIZES Bus 142Y.
		MSIVs close due to loss of RPS busses.
11:50		Primary containment coolers (VP) chilled water isolation valves isolate due to loss of RPS busses.
		A RHR Service Water pumps started manually for suppression pool cooling.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION							Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					Page (3)
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LaSalle County Station 1	0 5 0 0 0 3 7 3	9 3	-	0 1 5	-	0 0	1 2 OF 1 7

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

ATTACHMENT A CONTINUED

	Drywell Instrument Nitrogen (IN) is lost due to closure of containment isolation valves due to loss of RPS busses.
11:51	Both SBGT fans start due to loss of RPS busses.
	A RHR started manually for suppression pool cooling.
11:52	Reactor high pressure alarm occurs (1020 psig)
11:53	K Safety/relief valve (SRV) opened and closed on pressure. This is not the expected first SRV to open on pressure.
	A/B RPS MG sets restarted.
	U SRV opened manually.
11:54	S SRV opened manually. Low-low set (LLS) initiates due to two SRVs open as expected.
	Reactor high pressure alarm clears (1020 psig)
	1B RPS bus re-energized
11:55	1A RPS bus re-energized
11:56	Instrument air (IA) receiver air pressure low alarm received.
11:57	Suppression Pool temperature high alarm (105 degrees) This is an LGA-03 entry condition.
11:58	S SRV closed
11:58	U SRV auto closed by LLS logic. With the SRVs closed, Reactor Level shrinks due to the collapse of voids below level 8 trip
	MCC 134Y 480vac normal (From 142Y ,4.16KV bus)
	RCIC manually started for injection into the core

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION								Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)						Page (3)
		Year		Sequential Number		Revision Number		
LaSalle County Station 1	0 5 0 0 0 3 7 3	9 3	-	0 1 5	-	0 0		1 3 OF 1 7

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

ATTACHMENT A CONTINUED

	HPCS pump manually started to place a load on 1B DG. HPCS placed in full flow test. Division 3 bus has no designed crosstie.
12:00(-)	LGA-CM-01 jumpers installed per LGA-03 (EOP)
12:02	Suppression Pool temperature reaches 110F due to SRV's and RCIC.
12:03	B RHR Service Water manually started to support suppression pool cooling.
12:04	B RHR pump was placed in suppression pool cooling.
12:06	The Main Condenser low vacuum alarm occurs.
12:08	Primary Containment Pressure increases above 1.0 psig.
	RCIC placed in full flow test and injection is secured.
12:09	Drywell air temperature reaches 135F. Another LGA-03 entry condition.
12:11	The 1B VP (primary containment chillers) loop isolation valves opened.
12:12	The 1A VP loop isolation valves opened.
12:13	Restored Bus 138 to normal manually.
12:14	Primary Containment pressure drops below 1.0 psig.
12:17	B RPS Motor Generator Set tripped the second and final time from motor fault.
12:20	Power restored to busses 131X and 131Y Manually.

SRV cycling in alphabetical sequence continues throughout the event to control/reduce reactor pressure. Reactor level shrink and swell accompany the SRV cycles. RCIC is used to control reactor level and pressure.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION								Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)						Page (3)
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LaSalle County Station 1	0 5 0 0 0 3 7 3	9 3	-	0 1 5	-	0 0		1 4 OF 1 7

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

ATTACHMENT A CONTINUED

12:20(-) LGA-VP-01 jumpers installed to allow Drywell Chiller isolation to be reset per LGA-03.

12:25 NARS phone call made to report the Alert Condition. EAL 9.C. was cited.

12:47 ENS Notification Made

12:51 Bus 137X/Y Energized manually.

12:57 Service Water (WS) Pump Discharge Pressure Normal (indicative of WS Pumps back on line.

12:57 Division 1 4.1 kV bus crosstied to Unit 2, 0 Diesel Generator Shutdown, placed in Standby.

13:04 Division 2 4.1 kV bus crosstied to Unit 2, 1A Diesel Generator Shutdown, placed in Standby, Unit 2 Station Air Compressor Started. Unit 2 Turbine Building Closed Cooling Water System Started to support Air Compressor Operation.

13:18 C suppression chamber to drywell vacuum breaker opens, as expected due to SRV and RCIC adding inventory to suppression pool.

13:35 LGA-02 (EOP) Entered due to High Main Steam Tunnel Temperature.

13:45 Control transferred to TSC.

14:02 Unsuccessful attempt to open D SRV.

14:04 Instrument Air pressure Normal.

14:16 Reactor pressure at 500 psig.

RCIC Check valves appear to have not full closed.

14:54 Temporary power to fuel pool cooling (FC). Unit 2 FC system started.

15:47 Started Turbine Building Ventilation

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION — Form Rev 2.0

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					Page (3)
		Year		Sequential Number		Revision Number	
LaSalle County Station 1	0 5 0 0 0 3 7 3	9 3	-	0 1 5	-	0 0	1 5 OF 1 7

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

ATTACHMENT A CONTINUED

17:04 to 19:17	Using ADS high oressure air to open SRVs.
17:08	Primary Containment Pressure High alarm, 1 psig.
17:11	LPCS Pump ON, and is now used for level control. RCIC is used to a lesser extent from here on. LPCS Injection Valve opened and closed to maintain level.
19:07	Temporary Feed Established to B RPS Bus from Alternate Feed. Isolation can be reset.
19:23	Drywell instrument air crosstie to station instrument air established. Regulator Supply alarm clears
19:26	A/B/C/D MSIV Accumulators Normal Pressure. Instrument air established to drywell.
19:50	RWCU isolation valves opened.
19:52	1G33-F034 closed
19:53	RCIC Injection Valve closed and RCIC Injection check valve 1E51-F066 Closed. This is the final use of RCIC, and the 1E51-F065 doesn't full close.
20:07	Preparing to start RWCU as indicated by valve manipulations.
20:10	RWCU started per Operations Director log.
20:11	LPCS Injection Valve Open - Indications of testable check valve indication problems.
20:25	RCIC Steam Pressure Low, reactor pressure has dropped to approximately 57 psig.
21:25	CRD Pump on, suction lined up to Condenser Hotwell
21:27	Cycled Vacuum Breakers per surveillance due to SRV usage.
21:[illegible]	SCRAM Reset

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION									Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					Page (3)		
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LaSalle County Station 1	0 | 5 | 0 | 0 | 0 | 3 | 7 | 3	9 | 3	-	0 | 1 | 5	-	0 | 0	1 | 6	OF	1 | 7

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

ATTACHMENT A CONTINUED

22:43	Suppression Pool Temperature Drops to less than 110 degrees F
22:44	A RHR Pump shutdown to prepare A RHR system for Shutdown Cooling.
9/15/93	
00:44	Shutdown Cooling Line Temperature high alarm received (indicative of line warm up in preparation to establish shutdown cooling.)
04:40	1B33-F023A fails to close on first attempt, closes on second attempt.
04:59	A RHR Pump ON - Shutdown Cooling Established
09:48	Bulk Suppression Pool Temperature Normal, 105 degrees F.
10:46	Suppression Pool Bulk Temperature Normal Div 2
11:03	Suppression Pool Bulk Temperature Normal Div 1
11:50	Operating Condition 4, Cold Shutdown is reached. LGA-01 is exited.
13:20	Unit 2 Reactor Building Ventilation is started.
13:22	Unit 1 Reactor Building Ventilation is started.
13:30	Exit LGA-02
14:24	LPCS pump shutdown
15:15	UAT Energized- Power Available
16:44	Division 1 4.1 kV fed from UAT.
16:48	6.9 kv Bus 151 Picked up, along with 480 volt sub-busses
16:48	GSEP Alert Terminated and ENS notification made in this timeframe.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION							Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					Page (3)
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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

ATTACHMENT A CONTINUED

16:56 6.9 kv Bus 152 Picked up, along with 480 volt sub-busses

16:58 NARs for termination issued.

17:05 TSC secured.

9/16/93

19:40 Exit LGA-03

LER No. 412/93-012
Beaver Valley Unit 2

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LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

APPROVED BY OMB NO. 3150-0104
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FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Beaver Valley Power Station Unit 2	05000 4 1 2	1 OF 06

TITLE (4)
Emergency Diesel Generator Sequencer Circuit Deficiencies

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									N/A	05000
11	06	93	93	0 1 2	0 0	12	06	93	FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9): 5
POWER LEVEL (10): 000

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)	X	50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
L. R. Freeland, General Manager Nuclear Operations	4 1 2 6 4 3 - 1 2 5 8

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
A	EK	TMR	A611	N						

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately 15 single-spaced typewritten lines) (16)

On 11/04/93, a test to verify the automatic loading capability, on a Safety Injection Signal (SIS), for the 2-1 Emergency Diesel Generator (EDG) failed. The Unit was in Cold Shutdown at the time of the testing. The test verifies that all loads will deenergize on the respective safety-related emergency busses and that the EDG sequencer circuitry will automatically load safety-related loads at specfied time intervals, following starting of the EDG. On 11/06/93, the 2-2 EDG also failed its respecuve test for automatic loading capability. The cause of the test failures was the misoperation of a digital (microprocessor based) solid state timer associated with the Load Sequencer circuitry. An inductive voltage surge was produced by the deenergization of auxiliary relays within the Load Sequencer circuit during the SIS reset of sequencer operation. This caused the timer to misoperate resulting in the failure of the sequencer. Voltage suppression diodes were added to the auxiliary relays within the sequencers' circuit to eliminate the voltage surge. This event constituted a common mode failure which could have safety implications during an event involving a loss of offsite power and safety injection actuation. Operator action may have been required to manually sequence Emergency Diesel Generator loads.

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NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503

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Beaver Valley Power Station Unit 2	05000 4 1 2	9 3	- 0 1 2 -	0 0	02 OF 06

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

DESCRIPTION OF EVENT

On November 4, 1993, with the Unit in Cold Shutdown, a surveillance test to verify the automatic loading capability, on a Safety Injection Signal, for the 2-1 Emergency Diesel Generator failed. The surveillance test, performed on a refueling frequency, verifies that all loads will deenergize on the respective safety-related 4160Volt and 480Volt emergency busses and that the Emergency Diesel Generator circuitry will automatically load the safety-related loads onto the emergency busses at specfied time intervals following starting of the emergency diesel generator. The emergency diesel generator 2-1 sequencer failure was originally determined to have been a safety injection relay malfunction. The safety injection relay was replaced and the emergency diesel generator was re-tested satisfactorily on November 5, 1993.

On November 6, 1993, at 1357 hours, the 2-2 Emergency Diesel Generator failed its respective surveillance test for automatic loading capability. The actual cause for both emergency diesel generator sequencer failures was determined to be the intermittent misoperation of a digital solid state timer relay associated with the individual diesel's load sequencer circuitry. Auxiliary relays within the sequencer developed inductive voltage surges which caused the solid state timer relay circuitry to misoperate, preventing the required contact closures to energize auxiliary relays which would start safety-related loads. The 2-1 and 2-2 emergency diesel generator sequencers were verified to operate correctly in response to an undervoltage condition (Loss of Offsite Power). Since Safety Injection and Containment Isolation Phase "B" (CIB) actuation are not required to function during Cold Shutdown, the 2-1 Emergency Diesel generator was maintained operable by defeating the safety injection and CIB input signals to the diesel generator circuitry.

Post-event bench testing of the digital solid state timer relay identified the intermittent misoperation condition. The misoperation occurred in approximately thirty-three (33) percent of the bench test cycles. Circuit modifications to add voltage transient suppressor diodes in parallel with the auxiliary relay coils (See Figure 1) on both emergency diesel generator sequencer circuits were performed. These voltage suppressor diodes suppress the voltage surge created when the auxiliary relay coil is deenergized.

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LICENSEE EVENT REPORT (LER)
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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Beaver Valley Power Station Unit 2	05000 4 1 2	9 3	- 0 1 2 -	0 0	03 OF 06

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

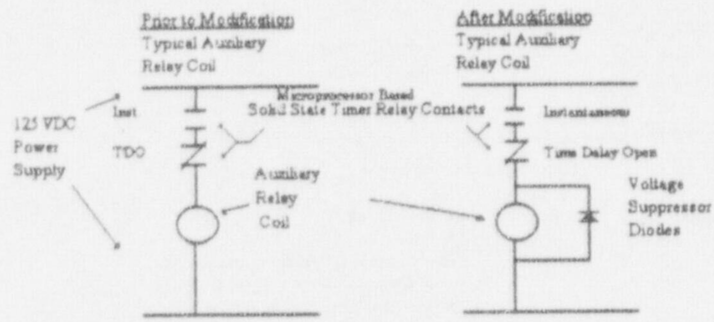

Figure 1

A problem with the start circuit for the 23A Motor Driven Auxiliary Feedwater Pump was identified during post-modification testing of the 2-1 Emergency Diesel Generator Sequencer circuit. Auxiliary relays operate to start safety-related components during sequencer operation. This start circuit has a set of parallel contacts which are closed by various start circuits. (See Figure 2 below). Following these contacts there is another set of parallel contacts associated with the auxiliary relay sequencer circuitry. The contacts for the auxiliary relays in the component start circuits are closed. The sequencer causes one set of parallel contacts to open, effectively blocking component operation until the specified step at the prescribed sequencer time interval. The remaining parallel contact is also closed and is opened by the sequencer timer relay and subsequently re-closed at the specified time interval causing the respective component to start. The addition of the voltage supressor diodes on the auxiliary relay coil for the 23A Motor Driven Auxiliary Feedwater Pump start circuit caused the drop-out time (the length of time required for relay contact opening) to increase a slight amount. This resulted in the relay contacts remaining closed upon initiation of the the first sequencer interval operation. This caused the 23A Motor Driven Auxiliary Feedwater Pump to start earlier in the loading sequence.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

Prior to Modification

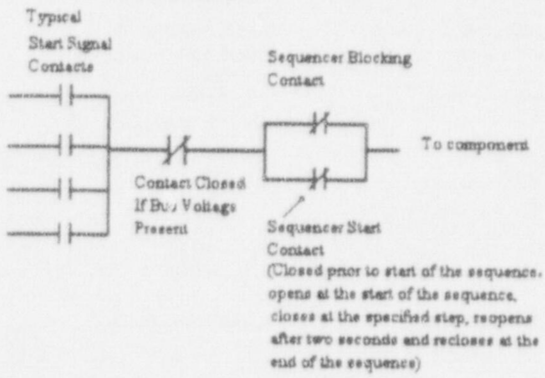

Figure 2

This problem was corrected through additional wiring changes (See Figure 3 Below). This modifiction was performed on the associated circuitry for both motor driven auxiliary feedwater pumps circuitry.

After Modification

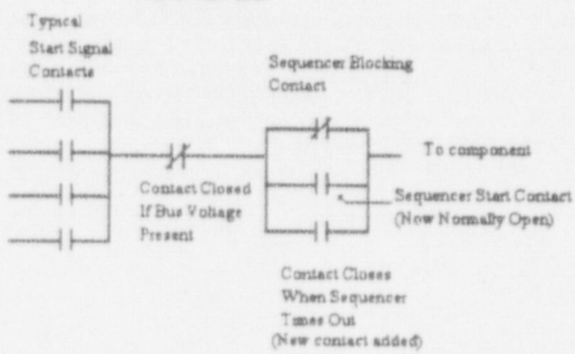

Figure 3

NRC FORM 366A (5-92)

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

The 2-1 Emergency Diesel Generator was functionally tested and returned to service on November 16, 1993. The 2-2 Emergency Diesel Generator was functionally tested and returned to service on November 17, 1993.

CAUSE OF THE EVENT

The cause for the emergency diesel generator (EDG) failures was identified as inadequate design understanding prior to implementation, and insufficient post modification testing following the installation of the digital (microprocesser based) solid state timers. The design changes were made to the EDG Load Sequencers during the Second Refueling Outage and also following digital solid state timer circuit modifications performed during the Third Refueling Outage. The testing conducted did not adequately validate the design change from electro-mechanical to microprocessor based solid state timers. An inductive voltage surge was produced by the deenergization of auxiliary relays within the load sequencer circuitry which caused the solid state timer to misoperate. The timer relays are Automatic Timing & Controls Company, Model 365-A, Long Range Timers. These timers were recommended by the manufacturer as direct replacements for the original electo-mechanical timers, where improved timing accuracy is desired.

REPORTABILITY

This event was reported to the Nuclear Regulatory Commission on November 6, 1993, at 1527 hours, in accordance with 10CFR50.72.b.2.i, as a condition found while the reactor is shut down, that had it been found while the reactor was in operation, would have resulted in the nuclear power plant being in an unanalyzed condition. This written report is being submitted in accordance with 10CFR50.73.a.2.v, as a condition that alone could have prevented the fulfillment of the safety function of systems that are needed to mitigate the consequences of an accident. Additionally is it being reported in accordance with 10CFR50.73.a.2.vii, as an event where a single cause or condition caused at least one train to become inoperable in a single system designed to mitigate the consequences of an accident.

CORRECTIVE ACTIONS

The following corrective actions have been taken as a result of this event:

1. Voltage supression diodes have been added to the auxiliary relays to eliminate the effects of the voltage surge.

2. The motor-driven auxiliary feedwater pump start circuitry has been modified to ensure correct operation during the emergency diesel generator sequencer operation.

3. The 2-1 Emergency Diesel Generator was functionally tested and returned to service on November 16, 1993. The 2-2 Emergency Diesel Generator was functionally tested and returned to service on November 17, 1993.

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4. Since the digital solid state timers had been purchased commercial grade and qualified for Class 1E use, other solid state relay replacement components in Class 1E circuits that were qualification tested were evaluated to verify that they are qualified for their specific application.

5. An evaluation of the post-modification program practices will be conducted. Until completion of this evaluation, Engineering Assurance and System Engineers will review modification packages prior to installation and concur with the modification testing requirements.

6. Engineering guidelines will be developed which address engineering requirements for the application of digital solid state components as replacements for electro-mechanical or non-solid state components.

SAFETY IMPLICATIONS

This event constituted a common mode failure which could have safety implications during an event involving a loss of offsite power and safety injection actuation. Operator action may have been required to manually start Emergency Diesel Generator loads.

PREVIOUS OCCURRENCES

LER 92-004-00 involved the failure of the Emergency Diesel Generator Sequencer Timer Relays due to the application of excessive voltage to the clock circuit.

DIESEL GENERATOR RELIABILITY

The following is a summary of the past 20, 50 and 100 start and load demands for the Unit 2 emergency diesel generators, trended in accordance with NUMARC 87-00 Rev. 1, Appendix D (Data as of November 6, 1993):

Unit 2

	Start Failures	Load Failures	Total	Trigger
Past 20 Site Demands	0/20	2/20	2/20	3/20
Past 50 Site Demands	0/50	2/50	2/50	4/50
Past 100 Site Demands	0/100	2/100	2/100	5/100
EDG 2-1 Past 25 Demands	0/25	1/25	1/25	4/25
EDG 2-2 Past 25 Demands	0/25	1/25	1/25	4/25

NRC FORM 366A (5-92)

LER No. 413/93-002
Catawba Unit 2

NRC FORM 366 (5-92)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)		ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Catawba Nuclear Station, Unit 1	05000413	1 OF 19

TITLE (4): Technical Specification 3.0.3 Entered Due To Inoperable Pump Discharge Valves

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME: CNS, Unit 2	DOCKET NUMBER: 05000414
02	25	93	93	002	00	04	05	93	FACILITY NAME:	DOCKET NUMBER: 05000

OPERATING MODE (9): 1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)			
POWER LEVEL (10): 100	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
	20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
	20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
	20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
	20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
R. C. Futrell, Compliance Manager	(803)831-3665

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On February 25, 1993, at 1431 hours, with Unit 1 in Mode 1, Power Operation, at 100 percent power, and Unit 2 in No Mode, Defueled, "B" train Nuclear Service Water (RN) System pump discharge valves (1(2)RN38B) failed to open during RN pump start. At 1745 hours, Unit 1 entered Technical Specification (TS) 3.0.3 due to both trains of RN being inoperable due to "A" train having a potential for similar problem. At 2205 hours, valve 1RN38B was declared operable and Unit 1 exited TS 3.0.3. Failure of the RN pump discharge valves to open has been attributed to a lack of detailed information in the motor operated valve (MOV) torque switch setup procedure, sizing variables that are possibly inadequate for these specific applications and/or a potentially degraded valve subcomponent. Corrective actions include adjusting valve settings for both Unit 1 and Unit 2 valves, evaluating similar valves in other applications, and further Engineering evaluation and testing. During this event, Operations failed to perform a Power Availability Test within one hour of declaring the Diesel Generators inoperable due to RN being inoperable. This resulted in a TS Surveillance being missed. The missed TS Surveillance is attributed to policy guidance that was not well defined or understood. Corrective actions included performing the TS Surveillance, developing a TS Interpretation, and training.

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BACKGROUND

Background for RN System

The discharge valves [EIIS:V] that failed to open and are the subject of this report are in the Nuclear Service Water [EIIS:BI] (RN) system. A simplified flow diagram of the RN system is included in the report as Attachment A. The flow diagram will help to understand the arrangement of the components discussed in this report.

The Nuclear Service Water System (RN) provides essential auxiliary support functions to Engineered Safety Features (ESF) of the station. The system is designed to supply cooling water to various heat loads in both the safety and non-safety portions of each unit. Provisions are made to ensure a continuous flow of cooling water to those systems and components necessary for plant safety during normal operation and under accident conditions. Sufficient redundancy of piping and components is provided to ensure that cooling is maintained to essential loads at all times.

Functionally, the system consists of four sections which serve to assure a supply of water to various station heat loads and return the heated effluent back to its heat sink. These sections are the source and intake section, the RN pumphouse section, the station heat exchanger [EIIS:HX] section, and the main discharge section.

Lake Wylie is the normal source of nuclear service water. A single transport line conveys water from a Class 1 seismically designed intake structure at the bottom of the lake to both the A and B pits of the RN pumphouse serving the RN pumps [EIIS:P] in operation. Should Lake Wylie be lost due to a seismic event in excess of the design of Wylie Dam, the Standby Nuclear Service Water Pond (SNSWP), formed by the Class 1 seismically designed SNSWP Dam, contains sufficient water to bring the station safely to a cold shutdown condition under all normal, transient, and accident conditions. The SNSWP has an intake structure designed to Class 1 seismic requirements, with two Class 1 seismic, redundant lines to transport water independently to each pit in the RN pumphouse. Automatically upon loss of Lake Wylie (as detected by RN pump pit level instrumentation), Lake Wylie double isolation valves are closed and the SNSWP valves are opened to both pit A and pit B.

RN pumps 1A and 2A take suction from pit A and discharge through RN strainers [EIIS:FLT] 1A and 2A respectively. The outlet piping of the 1A and 2A RN strainers then join back together to form the train A supply line to train A components in both units. RN pumps 1B and

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2B take suction from pit B, discharging through RN strainers 1B and 2B respectively. The outlet piping of strainers 1B and 2B join together to form the train B supply line to train B components in both units. The operation of any two pumps on either or both supply lines is sufficient to supply all cooling water requirements for unit startup, cooldown, and refueling and post-accident operation of two units. However, one pump has sufficient capacity to supply all cooling water requirements during normal power operation of both units or during post-accident conditions if the unaffected unit is already in cold shutdown. All four pumps are started during a postulated combined accident and loss of normal power. During an accident, a safety injection signal automatically starts all four pumps.

Nuclear service water is used in both units to supply both essential and non-essential components. Essential components are those necessary for safe shutdown of the unit, and must be redundant to meet single failure criteria. Non-essential components are not necessary for safe shutdown of the unit, and are not redundant. Each unit has two trains of essential heat exchangers designated A and B, and one train of non-essential heat exchangers supplied from either A or B and isolated on Engineered Safety Features actuation. The following components or services are supplied by each essential header of the RN system:

- RN pump motor cooler
- RN strainer backflush
- RN pump bearing lube injection water
- RN pump motor upper bearing oil cooler
- Diesel Generator (D/G) engine jacket water cooler
- Diesel Generator building essential fire water
- Diesel Generator engine starting air aftercooler
- Component cooling heat exchanger
- Assured auxiliary feedwater [EIIS:BA] (CA) supply
- Assured fuel pool makeup
- Assured component cooling [EIIS:CC] (KC) system makeup
- Containment spray [EIIS:BE] (NS) heat exchanger
- Control room area chiller condensers (fed by Unit 1 essential headers only)
- Auxiliary shutdown panel air conditioning units
- Assured containment penetration valve injection [EIIS:JM] (NW) system makeup

There are two main discharge headers with train 1A and 2A components returning flow to the A header, and train 1B and 2B components returning flow to the B header.

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The RN system is designed to supply the cooling water requirements of a simultaneous LOCA on one unit and cooldown on the other unit assuming a single failure anywhere on the system, loss of offsite power, and loss of Lake Wylie. Upon complete train separation, both units are assured of having a source of water, at least one pump capable of supplying required flow on its associated train, and at least one essential header to provide cooling water to components served by RN.

<u>RN Pump Discharge Isolation Valves 1RN28A, 2RN28A, 1RN38B, and 2RN38B</u>

These valves are Basic In Flow (BIF) butterfly valves required to be open when their respective nuclear service water pump is operating. The valves are interlocked to open when the associated RN pump is running and close when the pump is tripped. The valves do not directly receive an ESF signal themselves; however, the pumps are started on a safety injection signal from either unit or loss of offsite power. There are no control switches in the control room for these valves.

The pertinent RN system Technical Specification (TS), 3.7.4, requires that at least two independent RN loops shall be operable:

a) With both Units in Mode 1, Power Operation, Mode 2, Startup, Mode 3, Hot Standby, or Mode 4, Hot Shutdown, each loop shall contain two operable RN pumps and associated emergency diesel generators, two essential equipment supply and return headers, and a supply and discharge flow path capable of being aligned to the Standby Nuclear Service Water Pond (SNSWP).

b) With only one unit in Mode 1, 2, 3, or 4, each loop shall contain at least one operable RN pump, associated emergency D/G, and the essential equipment supply and return header associated with the unit in Mode 1, 2, 3, or 4, and a supply and discharge flow path capable of being aligned to the SNSWP.

Since both trains of RN on Catawba Unit 1 were determined to be inoperable, TS 3.7.4 could not be met because there is no action statement which addresses both trains of RN being inoperable. With both trains of RN inoperable, Unit 1 entered TS 3.0.3.

TS 3.0.3 is required to be entered when the Unit is operating in a condition not permitted by Technical Specifications. This condition exists when a Limiting Condition for Operation is not met except as provided in the associated Action Requirements. It requires that within one hour

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action shall be initiated to place the Unit in a Mode in which the specification does not apply by placing it, as applicable, in:

a) At least Hot Standby in the next 6 hours,

b) At least Hot Shutdown within the following 6 hours, and

c) At least Cold Shutdown within the subsequent 24 hours.

The Catawba Nuclear Station TS 3.0.3 interpretation states that the purpose of the one hour is to allow for preparation of an orderly shutdown before initiating a change in plant operation. It further states that if the equipment problem can be resolved within three hours, no load reduction is necessary. The remaining four hours leaves sufficient time to shutdown in a controlled and orderly manner, and well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is operable. The Unit 1 RN pump discharge valves were returned operable before any load reduction was required.

The Unit 1 RN pump discharge valves were setup in accordance with the requirements outlined in Generic Letter (GL) 89-10 which requires licensee to implement a program to ensure that all "safety-related" gate, globe, and butterfly valves are selected, set, and maintained to ensure ability to operate under their design basis conditions. This requires review of the design basis operating requirements and the actuator sizing calculation to determine the operating torque/thrust required to operate each valve. Individual valves are then diagnostic tested to measure and ensure the calculated torque/thrust is being delivered to the valve during a baseline or "static" (no pressure and flow conditions) test. A validation of the sizing calculation is then required within the timeframe of the 89-10 commitments by operating the valve against conditions of flow and pressure, or by providing some means of alternative justification. After initial validation, each valve is then periodically tested and maintained to ensure continued ability to operate. Unit 2 RN pump discharge valves are scheduled to be GL 89-10 tested during 2EOC6 outage in May 1994.

<u>Background for Missed TS Surveillance</u>

Since the RN system supplies cooling water the Diesel Generators (D/Gs), the loss of both trains of RN affected both D/Gs causing them to also become inoperable. The pertinent TS regarding

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power source availability is TS 3.8.11. This TS requires that as a minimum, the following A.C. electrical power sources shall be operable in Modes 1, 2, 3, and 4:

a) Two physically independent circuits between the offsite transmission network and the Onsite Essential Auxiliary Power System, and

b) Two separate and independent D/G's.

If both D/Gs are inoperable, the appropriate action to be taken is to demonstrate the OPERABILITY of two offsite A.C. circuits by performing Specification 4.8.1.1.1a within 1 hour and at least once per 8 hours thereafter; restore at least one of the inoperable D/G's to OPERABLE status within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore both D/Gs to OPERABLE status within 72 hours from time of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

Periodic test PT/1/A/4350/03 (Electrical Power Source Alignment Verification) is performed to verify proper breaker [EIIS:BKR] alignment, breaker operability, and power availability at the switchyard, 6900 V switchgear, 4160 V switchgear, 600 V essential load and motor [EIIS:MO] control centers, 120 VAC vital buses, and 125 VDC vital buses. This particular activity was not performed within one hour of declaring Unit 1 D/Gs inoperable.

EVENT DESCRIPTION

To fully understand the event that occurred on February 25, 1993, the history of the torque switch settings (TSS) for the RN pump discharge valves is provided as well as a detailed event description. A diagram is included as Attachment B to aid in the understanding of the previous TSS and operability of the RN pump discharge valves. Also, a simplified flow diagram of the RN system is included in this report as Attachment A.

In October 1988, PIR 0-C88-0314 was originated to address the problem associated with butterfly valves 1(2)RN-148A failing to open under high differential pressure (DP) conditions. The cause of the valves not opening was attributed to significant hardening of BIF seat materials. The seat hardening causes the valves to open at a higher unseating torque than the valves were setup to at the time. Corrective action identified fifty-six valves that needed to have their "open" torque switches reset to the maximum allowable TSS. Four of the fifty-six valves were the RN pump discharge valves.

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In July 1989, the corrective action of PIR 0-C88-0314 (seat hardening problem noted above) was performed on the RN pump discharge valves. The Unit 1 and Unit 2 RN pump discharge valves were to be adjusted to maximum "open" TSS (3.0). Unit 1 RN pump discharge valves were actually set to the maximum TSS. Unit 2 RN discharge valves TSS were inadvertently left at 1.5. The "closed" TSS was adjusted to maximum TSS (3.0) instead of the "open" TSS. The four RN pump discharge valves were part of the fifty-six valves noted above in PIR 0-C88-0314.

In December 1989, PIR 0-C89-0376/LER 413/89-029, was initiated because component cooling system (KC) valves 1KC-81B and 2KC-56A may not have sufficient torque output to overcome additional friction due to seat hardening. Corrective action was to modify the KC valves with an open torque switch bypass.

In March 1990, NRC issued IEN-90-21 which addressed increased seat friction on butterfly valves due to seat hardening. This document was issued based on the Catawba event discussed in PIR 0-C89-0376/LER 413/89-029.

In August 1992, Unit 1 RN pump discharge valves were setup per GL 89-10 criteria. The TSS for Unit 1 RN discharge valves were changed from 3.0 to approximately 2.0 for the "open" position because the required torque to open the RN pump discharge valves equates to a TSS of approximately 2.0. Unit 2 valves are scheduled to be setup to GL 89-10 during 2EOC6 outage in May 1994. Their TSS remained at 1.5 for the "open" position.

> The TSS described above indicates the status of the RN pump discharge valves prior to this event. The following information describes the specific event that lead to the discovery of the RN pump discharge valves problem.

On February 25, 1993, Unit 1 was in Mode 1, Power Operation, at 100% power, and Unit 2 in No Mode, Defueled, with RN pump 1A running to supply necessary cooling water.

At 1140 hours, RN pump 1B was started to perform an Inservice Pump Test (IWP). The "A" and "B" train headers were isolated due to train crossover valves being closed. This action depressurized "B" train header.

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At 1424 hours, RN pump 1B was shutdown upon completion of the IWP test. RN pump 2B was then started to perform its IWP test. Upon starting RN pump 2B, discharge valve (2RN38B) failed to open. The header downstream of the valve was depressurized, so this valve was trying to open against maximum different pressure.

At 1426 hours, RN pump 2B was shutdown and RN pump 1B was restarted to verify that its discharge valve would open. The discharge valve (1RN38B) for 1B RN pump also failed to open with the header downstream of the valve depressurized.

At 1430 hours, Operations opened the RN crossover valve, which pressurized the "B" train header and allowed valve 1RN38B to open. RN pump 1B was shutdown. Operations contacted Engineering to ask for assistance in resolving the failure of RN discharge valves to open. Operations also initiated work orders to investigate why the "B" train RN pump discharge valves did not open during RN pump start.

At 1432 hours, RN pump 2B was restarted and discharge valve 2RN38B opened which previously failed to open with the "B" train header depressurized.

At 1600 hours, a meeting was held with Operations and Engineering personnel to review the status of the investigation into the failure of the RN pump discharge valves.

At 1730 hours, after reviewing Engineering information and the results of the inspection of the RN pump discharge valves. Engineering concluded that the failure of the "B" train valves was due to higher than expected torque to open the valves with the header downstream of the valves depressurized. Engineering also determined that the "A" train RN pump discharge valves had a similar setup and therefore potentially had a similar problem. Based on the conclusion, Engineering recommended that both trains of RN on Unit 1 be declared inoperable. Engineering also advised Operations of an immediate corrective action which was to open the RN pump discharge valves and then remove power. Once the RN pump discharge valves were declared inoperable, Station Management continued to discuss potential reportability requirements.

At 1745 hours, Operations entered Unit 1 into TS 3.0.3 due to both trains of RN being inoperable based on input from Engineering.

At 1805 hours, Operations opened RN pump discharge valves and then removed power to the valves in order to assure the RN pumps would be available.

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At 1845 hours, the Electrical Power Source Alignment Verification Test (PT/1/A/4350/03) should have been performed within one hour of declaring the Diesel Generators inoperable due to both trains of RN being inoperable.

At 2015 hours, following further discussion with Engineering, Station Management concluded that a one hour notification to NRC per 10CFR50.72(b)(ii)(B) was required due to RN system being "Outside Design Basis".

At 2030 hours, the one hour notification was made to the NRC.

At 2035 hours, Operations performed Electrical Power Source Alignment Verification Test (PT/1/A/4350/03) to meet the requirements of TS Surveillance 4.8.1.1.1a.

At 2048 hours, based on Engineering's evaluation, Operations restored power to Unit 1 and Unit 2 RN pump discharge valves in preparation for changing the setup on the Unit 1 valves. Engineering determined that the Unit 1 discharge valves should be placed 20 degrees opened so that the valves would open against full differential pressure.

At 2130 hours, valve 1RN38B was positioned at 20 degrees open and was tested with the RN header downstream of the valve depressurized. Valve 1RN38B opened when 1B RN pump was started and was declared operable. At 2205 hours, Unit 1 exited TS 3.0.3. Operations then entered TS 3.7.4 which requires returning one train of RN within 72 hours.

On February 26, 1993, at 0030 hours, following Engineering evaluation, valve 1RN28A was positioned at 20 degrees open. 1A RN pump was started and valve 1RN28A opened against full differential pressure and was declared operable. At 0115 hours, Unit 1 exited the 72 hour TS Action Statement.

On February 27, 1993, while working to return Unit 2 valves to operable status, Engineering discovered that the torque switch settings for valves 2RN28A and 2RN38B were reversed when they were setup in 1989. The Unit 2 RN pump discharge valves were adjusted to the maximum TSS (3.0). The valves were tested with the header downstream of the valves depressurized and the valves tested successfully. Valves 2RN28A and 2RN38B were declared operable.

The following actions were taken after Unit 2 valves were returned to operable status on February 27, 1993.

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DP tests were performed on RN pump discharge valves (1RN28A and 1RN38B) to measure unseating and dynamic torque loads under flow and pressure conditions. The unseating and dynamic torque load were higher than was predicted by the manufacturer sizing calculations for the valves.

A DP test was performed on the as found TSS (1.5 "open") position of valve 2RN28A with the header depressurized. Valve 2RN28A actuator tripped and reset several times while trying to open. The valve finally opened but it took twenty-five additional seconds. The test results concluded that valve 2RN28A was operable as setup with TSS of 1.5 "open" with the header depressurized. Thus, valve 2RN28A was considered operable since 1980.

Engineering evaluated BIF motor operated valves in other applications. Valves 1(2)RN28A, 1(2)RN38B, 1(2)KC56A, and 1(2)KC81B were tested under DP conditions and tested successfully. These valves have a required safety function to open. Engineering also reviewed the manufacturer's sizing calculations for the RN pump discharge valves.

Valve 2RN38B was replaced with a new valve of different design and manufacturer. The new valve was a Fisher posi seal butterfly valve. The valve was tested and tested successfully. Engineering reviewed the test data and found the results to be acceptable.

Engineering is continuing to analyze the data from diagnostic tests and is continuing to conduct testing to identify causes of higher then expected torque requirements.

CONCLUSION

Conclusion of RN Pump Discharge Valves

The period of time from August 1992 through February 1993, three of the four RN pump discharge valves (1RN28A and 1(2)RN38B) were unable to open against full differential pressure. This results in a potential loss of RN to both Catawba Nuclear Station (CNS) units assuming a single failure of the one operable RN pump discharge valve.

Failure of the Unit 1 discharge valves 1RN28A and 1RN38B to open has been attributed to sizing variables that are possibly inadequate for a reason unique to these specific applications and/or a potentially degraded valve subcomponent. Corrective actions included setting the Unit 1 discharge valves to 20 degrees open, setting Unit 2 valves to maximum TSS (3.0), evaluating BIF motor operated valves in other applications, reviewing of the manufacturing sizing

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calculations, analyzing data from diagnostic testing and conducting additional testing to identify causes of higher than expected torque requirements.

Data recorded after the event from DP testing of valves 1RN28A and 1RN38B indicates that both unseating and dynamic torque loads under flow and pressure conditions are higher than was predicted by the manufacturer sizing calculations for these valves. Detailed review of the sizing calculation has identified a number of factors or assumptions that can not easily be validated or may not be addressed specifically in the calculation. Seat hardening can increase the required unseating load, but there is not any well known method to predict the magnitude or potential for this occurrence. Factors are included for gearbox efficiency and turbulence in the system, but these also have some degree of assumption involved. Packing or bearing frictions beyond those assumed in the calculations will also result in higher than expected loads required to operate the valve.

The presently available technology for diagnostic testing of butterfly valves limits the ability to perform "separate effects" testing. Only the total load can be measured, so it is not possible to determine the portion that each of these individual factors contribute under in-plant testing conditions. Advances in technology and additional testing will likely be required to fully understand the significance of each factor in predicting the total load required to operate these valves.

Failure of 1RN28A and 1RN38B following setup per the GL 89-10 design calculation does not appear to indicate a generic problem with the BIF sizing equation since other BIF valves have been successfully operated under DP conditions. Both 1KC56A and 1KC81B were setup per the GL 89-10 sizing calculation during the 1EOC6 refueling outage (Summer '92), and successfully tested near their design basis conditions. Measured loads under the DP test conditions are bounded by the values predicted in the sizing calculation and used in the field setup. Sizing of these valves used the same basic equations as the RN system valves to predict the operating torque requirements. Major differences in these applications is use of raw water for RN versus a treated water system for KC. Also their design calculations included different factors selected by the manufacturer with the intent of addressing application specific conditions such as valve location relative to a pipe bend or pump. The successful operation of the BIF valves in the KC application indicates that the methodology used in the BIF calculation is valid. Any deficiency with this process would appear to be limited to the proper selection of application specific factors, or the possible degradation of components such that the initial factors no longer model the application. The attempt to ensure proper selection and subsequent validation of factors used

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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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in sizing calculations is the basis for implementation of a GL 89-10 Motor Operated Valve (MOV) program.

Failure of the Unit 2 discharge valves (2RN28A, 2RN38B) to open has been attributed to a lack of detailed information in the motor operated valves (MOVs) torque switch setup procedure (IP/0/A/3820/04). Enclosure (11.1) that provided a diagram of the actuator, did not specify which adjusting screw was for the "open" or "close" switch and the switch itself was not clearly marked for this purpose. The technician could have mistaken these two switches during the TSS adjustments made in 1989. Procedure IP/0/A/3820/04 was revised on April 18, 1990 and March 4, 1991. During these revisions the enclosure showing a diagram of the actuator was updated to identify the "open" and "closed" adjusting screws for the torque switch. These changes were made due to a concern identified by technicians when trying to identify "open" versus "close" setting adjustments. The procedure was revised as an enhancement prior to discovery of the switches being reversed. Corrective actions include setting the Unit 2 valves to maximum TSS (3.0) and verifying the TSS on similar valves to ensure they are properly adjusted.

Review of additional BIF valve applications has indicated that all remaining valves are set to meet their operating requirements. The valve design is such that the closing direction of the valve is assisted under flow and pressure conditions, so only valves with a function requiring them to open are of any concern for this potential problem. Of the GL 89-10 safety related, active valves, with open required function, 1(2)RN28A, 1(2)RN38B, 1(2)KC56A, and 1(2)KC81B are the only BIF valves. All of these valves have been verified to operate under DP conditions at their present settings and are considered operable. Six additional non-safety valves in the Auxiliary Feedwater (CA) system are included in GL 89-10 with function to open; however, these valves operate at a maximum DP of approximately 5 psi and have their "open" torque switch setting at the maximum allowable position. With this low operating DP and maximum torque switch setting, these valves are considered to be capable of opening. These valves will be further addressed under the GL 89-10 program.

Additional non GL 89-10 BIF valves which function to open were included in the review of BIF valve application; however, these are contained in air systems which operate at conditions of less than 1 psi. These low operating conditions would cause no more additional load on the valve than is seen during normal operation. These valves are considered acceptable from previous strokes at normal conditions.

All remaining BIF valves have been confirmed to require operation in the closing direction only. Some of this population have been setup under GL 89-10 design calculations; however, no DP

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testing has yet been conducted for this group. DP testing or some other means of validating these valves setup will be performed in accordance with GL 89-10. These valves are considered operable at their present setup due to the low torque requirement for closing the valves, and the fact that flow and pressure conditions assist in closing the valve. The assumption of low torque required for closing the BIF valve was confirmed by review of the DP test data taken for the Unit 1 KC valves.

Conclusion for Missed TS Surveillance

The failure to perform the TS Surveillance is attributed to policy guidance which was not well defined or understood. Shift personnel did not recognize the need to perform the surveillance test when RN was in TS 3.0.3. Shift personnel considered surveillance requirements for TS 3.0.3 to be more restrictive than TS Surveillance requirements for 4.8.1.1.1a, so they thought they did not have to perform the power availability test.

Corrective actions include preparing a TS Interpretation to address TS Surveillance requirements of TS 4.8.1.1.1a when TS 3.0.3 is entered. Training will also be provided to operators on the TS Interpretation.

A review of the Operating Experience Program (OEP) database for the past 24 months prior to this event did not identify any reportable events attributed to policy guidance not well defined or understood concerning missed TS Surveillances involving power alignment surveillances. No reportable events were attributed to information in procedures being too generic, or analysis deficiency involving RN system. Both of these events are considered not to be recurring.

CORRECTIVE ACTIONS

SUBSEQUENT

1) Adjusted discharge valves (1RN28A and 1RN38B) to 20 degrees open per work order 93016083-01 and 93016077-01. Successfully tested the valves with header downstream of the valves depressurized.

2) Adjusted discharge valves (2RN28A and 2RN38B) to maximum TSS per work order 93016227-01 and work order 93007497-01. Successfully tested the valves with the header downstream of the valves depressurized.

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3) Evaluated BIF motor operated valves in other applications.

4) Reviewed the manufacturers sizing calculations for the RN pump discharge valves.

5) Valve 2RN38B was removed on March 20, 1993 and replaced with a valve designed by a different manufacturer per work order 93020922-01. The valve was tested per work order 93020922-02 and the valve tested successfully. Engineering reviewed test data and found the results to be acceptable.

PLANNED

1) Engineering is continuing to analyze the data from diagnostic testing and to conduct additional testing to identify causes of higher than expected torque requirements.

2) Compliance will prepare a TS Interpretation concerning TS Surveillance requirements of TS 4.8.1.1.1a when TS 3.0.3 is entered.

3) Training will be provided on the TS Interpretation.

SAFETY ANALYSIS

Safety Analysis for Inoperable RN Pump Discharge Valves

This event has been evaluated by considering station response to design basis events. The period to be considered is from August 1992 through February 1993. The Past Operability evaluation for PIR 0-C93-0126 indicates that this is the time period when three of the four RN pump discharge valves (1RN28A and 1(2)RN38B) were unable to open against full differential pressure. This results in a potential loss of RN to both CNS units assuming a single failure of the one operable RN pump discharge valve.

A review of CNS design basis events indicates that the bounding event during the time period stated above would be a simultaneous Loss of Coolant Accident (LOCA) on Unit 2, Loss of Offsite Power (LOOP), and worst case failure of RN.

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The worst case RN failure is one that would depressurize the RN system such that the 1A, 1B, and 2B RN pumps would be isolated from the supply header. RN pump 2A and the associated isolation valve 2RN28A were capable of operating to pressurize the shared RN supply header if one of the other three pumps failed while running. Assume only RN pump 2A is running prior to a LOOP. A failure of D/G 2A to start would have been the worst case single failure and would have resulted in a loss of all RN.

A seismic event would not further impair the RN system and is not considered.

Limiting Design Basis Event

Assume a loss of all RN (failure of D/G 2A) simultaneous with a LOOP and large break LOCA. Three D/Gs would have started and powered the respective Essential Buses. Reactor Trip and Safety Injection is initiated automatically. The three idle RN pumps would have started and achieved dead head against the respective isolation valves.

Per the Safety Injection procedure, the Control Room (CR) would verify Reactor trip, Turbine trip, AC power, and safety injection. The procedure then requires verification of safety injection equipment alignment using the Monitor Light Panel. Indicators on the Monitor Light Panel for 1RN28A and 1(2)RN38B would be dark, alerting the CR to the loss of RN event.

All ESF response would occur as designed with the exception assumed single failure of the 2A DG. The KC system has sufficient heat capacity to support accident mitigation until initiation of containment sump recirculation. Given the worst case LOCA scenario of a double ended guillotine pipe break at the Reactor Coolant pump suction and one train of Emergency Core Cooling System (ECCS) in operation, sump recirculation will not begin sooner than 28.3 minutes into the event.

After 6 minutes, the D/G annunciators would begin to alarm due to high D/G Cooling water [EIIS:LB] (KD) system temperature.

At approximately 10 minutes past event initiation, the expected Control Room operator response would be to secure one of the operating Unit 1 D/Gs and the only operating Unit 2 D/G. In addition, the Control Room operator would also dispatch an non-licensed operator to the RN pump structure to manually align one or more RN pump discharge valves.

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A loss of all A/C would have occurred on Unit 2 from approximately 10 minutes into the event until RN could be manually aligned and D/G 2B restarted.

RN pump discharge valves would be manually aligned in less than 15 minutes from the time an operator is dispatched from the CR. Given that an operator is dispatched to the RN pump structure 10 minutes into the event, then at least one RN pump discharge valve would have been manually aligned 25 minutes into the event.

Assuming a loss of all A/C power at 10 minutes into the event and D/G 2B restart at 25 minutes, a period of 15 minutes exists when there would be no ECCS available. Duke analysis indicates that core damage during this period is a possibility, but is inconclusive as to whether core damage would have occurred. We have taken a conservative approach using NUREG 1465 source term technology in further analyzing the dose consequences of this event.

Were severe core damage to occur, the containment hydrogen concentration is predicted to reach values that could initiate a burn in some compartments when power is recovered. Hydrogen concentrations and resulting hydrogen burn containment pressure spikes are estimated to be of a magnitude which would not have threatened containment integrity.

The Westinghouse limiting case LOCA analysis under which CNS is currently operating indicates that ice bed melt out will occur 69 minutes into a large break LOCA event. Peak containment pressure is expected to occur at 122 minutes into the event. Since the loss of all A/C power occurs during ice melt out and prior to sump recirculation, long term containment pressure is not affected. Therefore, long term containment integrity is not threatened by the limited loss of RN event.

Dose analysis has been performed for the event described using NUREG 1465 source term technology and the offsite dose limits are within 10CFR100 limits.

Safety Analysis Conclusion

During the seven month period beginning August 1992 through February 1993 the Nuclear Service Water system could not have responded automatically to mitigate the consequences of Design Basis events considering the unlikely failure of RN pump 2A while running. Sufficient system redundancy exists to maintain the station in a safe condition following all credible events until RN could have been restored by manual operator actions. The Limiting Design Bases Event (simultaneous LOOP, LOCA, and Loss of RN) may have resulted in core damage, but

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10CFR100 dose release limits would not have been exceeded. The postulated worst case RN failure described in the Safety Analysis did not actually occur at CNS. The health and safety of the public were not affected by this event.

Safety Analysis for Missed TS Surveillance

On February 25, 1993, between 1745 hours and 2035 hours, the operability of offsite power sources was not verified as required by TS 4.8.1.1.1a. Offsite power was verified operable at 2035 hours by performance of Electrical Power Source Alignment Verification Periodic Test (PT/1/A/4350/03). No problems were discovered while performing the test. Offsite power source was available between 1745 hours and 2035 hours. In the event of a loss of offsite power, annunciators would have alerted the CR personnel. No related alarms were received during this time period. Therefore, it is apparent the redundant AC power sources were available the entire time D/G 1A and 1B were inoperable due to RN being inoperable. The health and safety of the public were not affected by this event.

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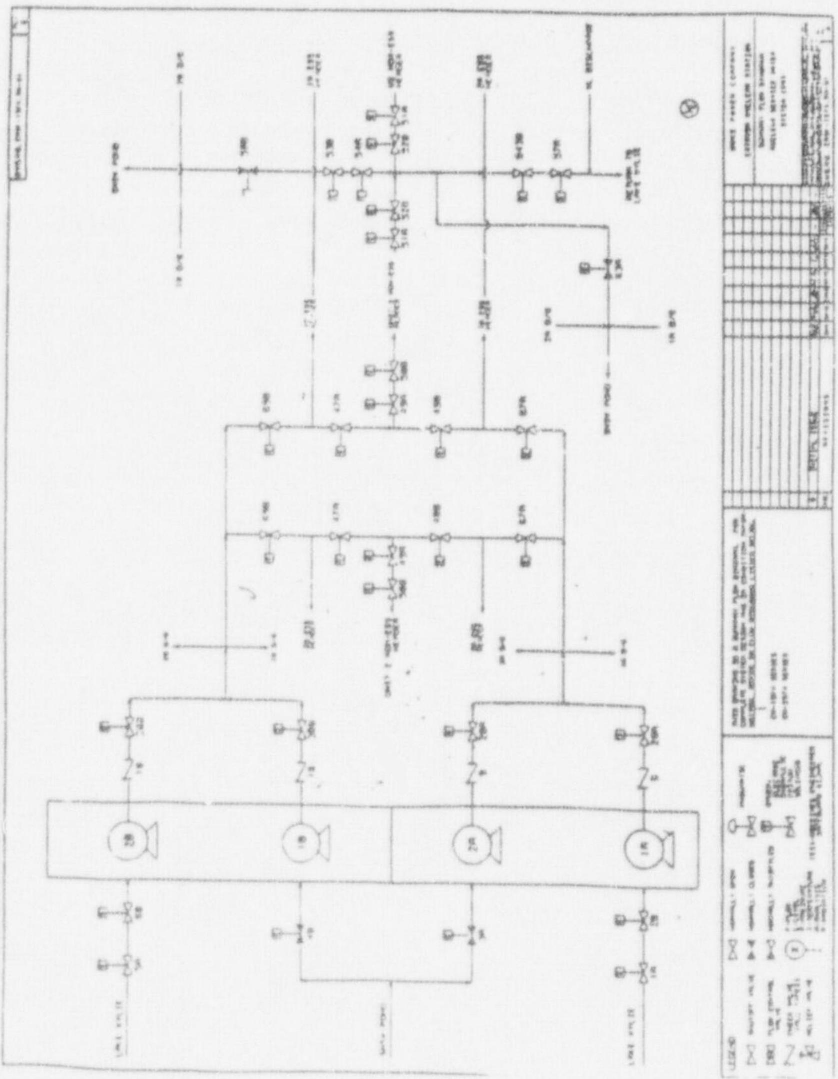
Attachment A



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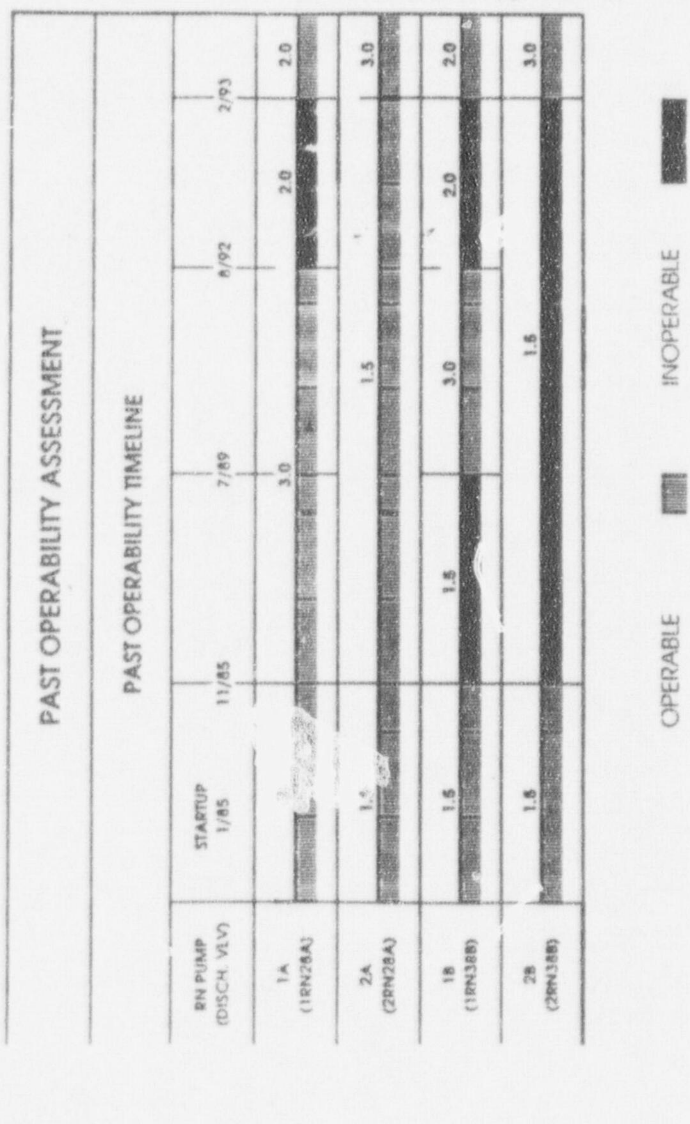
TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

Attachment B



NRC FORM 366A (5-92)

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Perry

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Perry Nuclear Power Plant, Unit 1	05000 440	1 OF 7

TITLE (4): Reactor Shutdown Due to Service Water Pipe Rupture

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
										05000
03	26	93	93	010	00	04	26	93	FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)			
POWER LEVEL (10)	100	20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Ron W. Gaston, Compliance Engineer Extension 5004	(216) 259-3737

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On March 26, 1993, at 1525 hours, a manual reactor scram was inserted due a rupture in a 30 inch section of underground Service Water piping. Prior to the event, leak isolation was in progress to determine the source of water which was earlier reported coming from the ground near the Water Treatment Building. An Alert was conservatively declared at approximately 1535 hours due to flooding in plant areas which potentially posed a threat to safe shutdown equipment.

All plant equipment functioned as designed during the plant shutdown with the exception of several minor equipment anomalies. No safety related equipment was affected as a result of the flooding.

The cause for the piping failure was attributed to induced axial piping stress caused by pipe bending as a result of a localized loss of soil support. Appropriate corrective action to effect repairs to the Service Water piping will be completed prior to plant startup. Additional corrective measures will also be taken to minimize water entry into plant buildings.

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I. Introduction

On March 26, 1993, at 1524 hours, a fast reactor shutdown was initiated due a rupture in a 30 inch section of underground Service Water piping. Prior to the event, the plant was in Operational Condition 1 (Power Operation) at 100 percent of rated thermal power. At 1535 hours an Alert was declared due to flooding of plant areas.

The following NRC notifications were completed to satisfy the applicable reporting requirements:

Reporting Requirement		Description
10 CFR 50.72(a)(i)	[1 hour]	To report the Alert declaration
10 CFR 50.72(b)(i)(v)	[1 hour]	To report difficulty manning the Technical Support Center (TSC) due to flooding
10 CFR 50.72(b)(2)(ii)	[4 hour]	To report the manual shutdown of the reactor
10 CFR 50.72(b)(2)(ii)	[4 hour]	To report various ESF actuations
10 CFR 50.72(b)(2)(vi)	[4 hour]	To report a news release concerning the Alert declaration

The 10 CFR 50.72 notification to report difficulty in manning the TSC was later determined to be not required since no loss of emergency assessment capability actually occurred.

This event is additionally being reported in this LER to satisfy the corresponding requirements of 10 CFR 50.73(a)(2)(iv) regarding the initiation of a manual reactor shutdown and ESF actuations.

Additionally, a Region III NRC Augmented Inspection Team was dispatched to the site between March 27 and April 2, 1993 to review the circumstances surrounding this event.

II. Description of the Event

At 1315 hours on March 26, 1993 water was reported coming from the ground near the Water Treatment Building [MH] at an approximate rate of 75 to 100 gallons per minute (gpm). Walkdowns of plant buildings in the surrounding areas were performed to identify any abnormalities. Concurrent with this activity, attempts were made to determine the source of the leak by systematically isolating potential water sources in the area. At 1328 hours, the Emergency Service Water (ESW) [BI] B loop was secured with no effect on the leak. The ESW A and C loops were not operating at that time. Between 1411 and 1447, similar isolations were performed on the Two Bed Demineralizer and Mixed Bed Demineralizer systems which also had no effect on the leak.

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At 1521 hours, the Service Water [KG] pump discharge header low pressure alarm was annunciated in the Control Room. The Control Room personnel responded by throttling the Nuclear Closed Cooling (NCC) [CC] heat exchanger [HX] bypass valve and starting the idle Service Water pump as directed by plant procedures. Shortly thereafter, plant personnel in the vicinity of the leak indicated that the amount of water coming from the area had substantially increased. At 1525 hours, the Shift Supervisor, who was at the leak site, directed the Unit Supervisor in the Control Room to commence a fast reactor shutdown in preparation for terminating Service Water flow. At 1526 hours the reactor was manually scrammed from 66 percent reactor power.

Control Room personnel entered Plant Emergency Instruction (PEI)-B13, "Reactor Pressure Vessel Control" at 1527, when reactor vessel water level dropped below Level 3 (178 inches above the top of the active fuel) due to level shrink after the scram. The lowest vessel level reached during the transient was 157 inches. At 1530, a plant cooldown was commenced using Reactor Core Isolation Cooling for level control and Bypass Valves for pressure control.

The plant had previously entered Off-Normal Instruction (ONI)-P41, "Loss of Service Water" prior to the fast reactor shutdown and continued with prescribed actions to stabilize the balance of plant systems supported by the Service Water System.

At 1535, an Alert was declared due to reports of significant flooding in plant buildings. The Service Water System was shutdown at approximately 1540 hours. At 1645 reactor vessel pressure control was shifted to the Safety Relief Valves (SRVs) [RV] due to the impending loss of condenser vacuum. Control Room Operators began closing Main Steam Isolation Valves (MSIVs) [ISV]. Main Condenser vacuum was manually broken at 1655 hours. An MSIV isolation signal was generated at 1658 as a result of the low condenser vacuum. All MSIVs and inboard drain valves had been manually closed prior to the isolation; therefore only the outboard drain valves repositioned in response to the isolation signal. Shutdown cooling utilizing Residual Heat Removal (RHR) A loop was established at 2014 hours on March 26, with the plant reaching cold shutdown (Mode 4) at 2210. At 0150 hours on March 27, 1993, the Alert was terminated and the recovery phase initiated.

III. Apparent Cause for the Pipe Failure

The eventual catastrophic failure of the 30 inch Service Water pipe is believed to have resulted from axial pipe stress caused by pipe bending due to a localized loss of soil support. The loss of soil support was caused by erosion from an existing leak on the underside of the pipe. It appeared that the leak had existed for an considerable period of time prior to the complete failure of the affected pipe section on March 26.

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The exact cause for the initial leak may never be definitively determined due to the loss of fragments of pipe material during the event. However, it is believed that the leak may have been the result of several contributing factors. These include an axial strength which was adequate for normal system service loads, but was insufficient to accomodate possible additional localized loads/stresses due to items such as laminate degradation over time, fabrication defects, or other similar deficiencies. An ongoing evaluation will continue to investigate potential causal factors associated with the initiating leak.

IV. Equipment Malfunctions and Anomalies

The following summary includes equipment problems which appeared to be directly associated with the March 26 event:

As stated previously, PEI-B13 was initially entered at 1527 on March 26. Entry into PEI-B13 requires that the hydrogen analyzers be placed into service. When the lineups were completed for placing the instruments in service, they indicated a hydrogen concentration of 2.5 percent for the drywell head and 1.5 percent for the containment dome requiring entry into PEI-M51/M56, "Drywell And Containment Hydrogen Control". Subsequent chemistry analyses confirmed that the instruments were giving false high readings and PEI-M51/M56 was exited.

While performing procedural steps directed by ONI-P41, a misinterpretation on the part of an operator resulted in a premature shutdown of both condenser hotwell pumps. The termination of condensate flow caused steam to be discharged directly into the Offgas System [WF] without being condensed. Necessary corrective actions to return the system to service will be completed prior to plant startup.

The pump casing for the A Service Water Screenwash Pump split at some time during the event. The cause for the material failure is unknown at this time. The ongoing investigation for this occurrence will determine if the cause was associated with the pipe rupture.

Additional equipment related items include minor cavitation noted for the Control Rod Drive (CRD) [AA] Pump A due to loss of suction during the event. An investigation did not reveal any evidence of damage resulting from the cavitation. A glycol skid in the Offgas building was wetted during the event causing problems with the associated electrical controls and indications. The extent of damage will be determined from followup corrective actions.

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V. Safety Analysis

As stated earlier, no safety-related equipment was affected as a result of this event and there were no radiological consequences associated with this event.

In the design for the Perry Nuclear Power Plant, an underground break of Service Water piping was not considered a significant threat for internal flooding of the plant or a challenge to the design capacity of the Underdrain System. Therefore, neither of these aspects are directly addressed in the Perry Updated Safety Analysis Report (USAR).

The Plant Underdrain System is designed for a postulated break in the 12 foot diameter Circulating Water System piping or failed expansion joints occurring inside the turbine building through flow from a fracture in the building basemat. The Underdrain System capacity is sized to accommodate the total volume of water from the design basis accidents (DBAs) described above, while maintaining the underground water level below Elevation (El.) 590-feet (ground level is El. 620-feet).

Although the internal and external pathways taken by the water during the March 26 Service Water System break were not specifically considered in the USAR Underdrain System analysis, the event was bounded by the DBA flooding scenarios.

A majority of the water inside the plant entered through spare conduits near the ceiling of Control Complex El. 599-feet. The conduits previously contained plugs which were expelled by the incoming water. The conduits are housed in an electrical penetration which originates in Electrical Manhole (EM) 1. EM 1, which is adjacent to the areas where the pipe rupture occurred, was not sealed; thereby allowing water to establish a gravity drain path through the electrical penetration and associated conduits.

Other buildings affected by internal flooding include the Auxiliary Building, Radwaste Building, Turbine Building, Intermediate Building, Turbine Power Complex and Emergency Service Water Pumphouse. Water in these buildings entered primarily through doors or electrical penetrations. Water levels in the buildings varied between 1 to 8 inches, below levels which could compromise the operability of any safety-related equipment. Therefore, since the flooding did not result in any safety related or safe shutdown systems being adversely affected, this event is not considered to be safety significant.

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VI. Similar Events

A previous event involving a catastrophic rupture of fiberglass piping occurred on December 22, 1991. The 1991 event was reported to the NRC in LER 91-027 and the Perry response to Confirmatory Action Letter (CAL) 91-016A, (PY-CEI/OIE-0388 L) dated February 3, 1992.

The cause for the 1991 event was attributed to a pre-existing construction defect, combined with a degraded pipe support, resulting in undesirable loading stresses being placed on a fiberglass elbow. The December 1991 event involved an above ground transition point between the fiberglass and steel piping for an auxiliary condenser. The specific causal factors associated with the recent event involving the Service Water pipe rupture appear to be unique and unrelated to the previous failure of the Circulating Water System piping.

Water intrusion into plant buildings occurred through similar pathways in both events. Corrective actions from the December 1991 event involving the sealing of conduits and manhole covers had not been fully implemented at the time of the March 26 event. However, administrative actions taken to maintain Underdrain System peizometer tube caps in place and maintain covers on manholes when not in use may have partially mitigated the effects of flooding during the recent event.

VII. Corrective Actions

The failed portion of the 30 inch Service Water pipe is being repaired with a conservatively designed fiberglass reinforced plastic (FRP) replacement pipe. Particular attention is being paid to the interface with the existing Service Water piping to ensure a smooth loading and stress transition. An ongoing investigation to determine the root cause for the pipe failure will continue to investigate potential causal factors associated with the initiating leak.

Substantial portions of the remaining Service Water piping are undergoing internal visual inspections to determine the extent of damage. Several types of laminate degradation have been identified and categorized with respect to structural significance. Those considered significant will be repaired prior to startup from the current forced outage.

Due to the above inspections and repairs, it is expected, with a high level of confidence, that the Service Water System will be acceptable for continued service until Refueling Outage (RFO) 6 (currently scheduled for March 1997). Further engineering evaluation will be performed to determine appropriate long term corrective action, if required, to ensure satisfactory Service Water operation beyond RFO 6.

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With regard to corrective actions for items described previously in Section IV, "Equipment Malfunctions And Anomalies":

1. The false readings indicated by the Hydrogen Analyzers were determined to be the result of leakage from fittings and valves on the Hydrogen Analyzer skids. One of the analyzers also required replacement of a catalyst cell. The Hydrogen Analyzers were satisfactorily calibrated after completing repairs.

2. Corrective actions required to restore the operability of the Offgas System will be completed prior to startup from the current forced outage. Procedures associated with the occurrence involving the Offgas System will be evaluated for potential enhancements.

3. The cause for damage to the Service Water Screenwash Pump casing will be determined as part of an ongoing evaluation. The evaluation will also determine whether the cause was directly associated with the Service Water pipe rupture.

4. The extent of water damage to the Offgas System glycol skid which was wetted during the event will be determined as part of overall followup corrective actions for this event.

5. Modifications will be implemented to seal identified water entry points for plant buildings.

The corrective actions summarized above are also included in a comprehensive listing of required actions being tracked by a Perry Incident Response Team (IRT). The IRT was established during the recovery phase of the March 26 event to coordinate investigations and evaluations associated with the event. Corrective actions are being prioritized for completion commensurate with their overall significance and will be completed under existing site procedures for corrective action and work control.

Energy Industry Identification System Codes are identified in the text as [XX].

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TITLE (4) Excessive Strainer Differential Pressure Across the RHR Suction Strainer Could Have Compromised Long Term Cooling During Post-LOCA Operation

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
										05000
04	19	93	93	-- 011 --	00	05	19	93	FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9)	4	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)							
			20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
POWER LEVEL (10)	0		20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v)		73.71(c)
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
			20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
			20.405(a)(1)(iv)	X	50.73(a)(2)(ii)	X	50.73(a)(2)(viii)(B)		
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Henry L. Hegrat, Compliance Supervisor Extension 5185	(216) 259-3737

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On April 19, 1993, an engineering evaluation identified that excessive strainer differential pressure across the Residual Heat Removal (RHR) Suction Strainers could have compromised long term cooling during and following 100 days of continuous post Loss of Coolant Accident (LOCA) operation.

The cause of the reduced capability of the RHR pump strainers is considered to be the inadequate cleanliness conditions in the suppression pool. The root causes include inadequate program requirements and inadequate personnel sensitivity to the effects of cleanliness on Emergency Core Cooling System (ECCS) operability. The design of the strainers was not considered to be a factor.

To prevent recurrence, ECCS strainers will be inspected prior to power operation, pump suction pressures will be monitored, visual inspections during Technical Specification Surveillances will be performed, and housekeeping and inspection standards for containment and drywell will be strengthened to ensure that an acceptable level of suppression pool cleanliness is maintained. The redesigned strainers will also provide additional margin with respect to minimizing the potential for strainer fouling, tolerance for accumulating debris, and ensuring structural integrity for all operating and accident loads.

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I. Introduction

On April 19, 199" an engineering evaluation identified that excessive strainer differential pre sure across the Residual Heat Removal (RHR) Suction Strainers [STR] could ha' compromised long term cooling during and following 100 days of continuous ost Loss of Coolant Accident (LOCA) operation. The NRC Operations Center was informed of the event via the Emergency Notification System at 1830 on April 19, 1993, pursuant to notification requirements identified in 10CFR50.72(b)(2)(i). This event is being reported under the requirements of 10CFR50.73(a)(2)(ii)(A), 10CFR50.73(a)(2)(ii)(B), 10CFR50.73(a)(2)(v)(B), and 10CFR50.73(a)(2)(vii)(B).

II. Event Description

On May 22, 1992, during Refueling Outage 3 (RF03), an inspection of the containment side of the suppression pool was performed using a remotely controlled submarine equipped with a video camera. The inspection identified various foreign objects on the pool floor, as well as accumulations of dirt and debris on the suction strainers for RHR [BO] System loops A and B. Other Emergency Core Cooling System (ECCS) strainers were also inspected and determined to be clean. A number of foreign objects were removed from the pool floor. Inspecting personnel recognized the fouling of the RHR strainers, but did not question the operability of the systems, based on the successful completion of all required surveillances. The decision was made to schedule the strainers for cleaning at a later date.

On January 16, 1993, during a maintenance outage, the strainers were cleaned and inspected. RHR A and B suppression pool suction strainers were found to be deformed, with the area of the strainer surface between internal stiffeners partially collapsed inward, in the direction of system flow. It was determined that the strainers had been deformed by excessive differential pressure caused by strainer fouling during normal pump operation. Although the duration of the strainer fouling problem could not be conclusively determined, review of the video tape previously taken in RF03 revealed evidence of deformation which had not been noticed at the time of the taping. The containment side of the suppression pool was inspected, videotaped, and cleaned in February, 1993, and debris samples were obtained for analysis. Following evaluation of the non-conformance, the deformed strainers were replaced. A condition report was initiated to investigate the circumstances surrounding the strainer fouling and subsequent deformation.

Following an unexpected shutdown on March 26, 1993, safety relief valves were utilized for reactor pressure control, and RHR A and B pumps were operated simultaneously in the suppression pool cooling mode for two hours. Following the shift of the RHR A loop to the Shutdown Cooling mode, RHR B was operated

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with suppression pool suction for an additional five hours. On April 14, 1993, all ECCS strainers were inspected using a high powered light and a video camera. The RHR B strainer was fouled and deformed in a manner similar to that observed during the January inspection; however, the remaining strainers showed no signs of fouling. Without disturbing the debris on the strainer, a test run of the RHR B pump was performed with suction pressure monitored. With a static suction pressure of 9.25 psig, pump running suction pressure decreased to an indicated 0 psig after approximately 8 hours of operation, and although the pump flow remained adequate, the pump was secured.

On April 19, 1993, an engineering evaluation determined that excessive strainer differential pressure across the RHR Suction Strainers could have compromised long term cooling during and following 100 days of continuous post Loss of Coolant Accident (LOCA) operation.

III. Cause Analysis

The cause of the reduced capability of the RHR pump strainers is considered to be the inadequate cleanliness conditions in the suppression pool. The root causes include inadequate program requirements and inadequate personnel sensitivity to the effects of cleanliness on ECCS operability. The design of the strainers was not considered to be a factor. A detailed discussion of these considerations is provided below.

Analysis of Suppression Pool Debris

Video tapes of the RHR A and B strainers taken in May 1992, February 1993, and April 1993 all clearly show debris and corrosion products entangled in or attached to fibrous material.

On February 11 and 14, 1993, samples were taken from the floor of the suppression pool. The February 11 sample consisted of fibrous material, two small pieces of metal and corrosion products. The fibers had different lengths, diameters, colors, and physical properties (fibers were twisted, multi-directional, straight, etc.). The two small pieces of soft metal appeared to be aluminum, and would be expected to remain on the pool floor and not contribute to ECCS suction strainer fouling. The source of this metal is unknown. The February 14 sample, taken from a different location on the pool floor, contained only corrosion products.

In April and May, five debris samples were taken directly from the RHR B suction strainer. All of these samples contained fibrous material, corrosion products, and miscellaneous debris such as pieces of griffolyn and herculite. The predominant fibrous material in all of these samples was glass fiber from roughing filter material used in the Drywell Air Cooler System.

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Fibers from Containment Vessel Cooling System roughing filter media, industrial filters used in maintenance applications, and other sources were also identified. In addition to a six square inc' piece of griffolyn in one of the samples, many small pieces of griffolyn and a uniform coating of corrosion products were entrapped in the fiber mat. X-ray fluorescence identified a predominance of iron oxide (Fe_2O_3) in the corrosion product material. Essentially, the strainer provided a structural framework for a uniform covering of the fibrous material, which acted as an effective filter for suspended solids that otherwise would have passed through the strainer.

The exact method of introduction of the fibrous materials into the suppression pool has not been conclusively determined; however, several possible explanations were evaluated. The roughing filters in the Containment and Drywell cooling units are normally replaced prior to startup from refueling outages, and remain installed in the systems throughout power operations. The thorough inspection and cleaning of the pool in April 1993 resulted in the removal of several intact pieces of Drywell Cooler roughing filter material from the suppression pool. At least one piece of filter material was removed intact from the B RHR strainer. A review of the repetitive tasks for filter replacement, and discussions with personnel who performed those tasks provided no indication that any roughing filter material was missing or blown out due to normal operation of the drywell air coolers.

Following the identification of the fibers on the RHR suction strainers, and in the effort to establish acceptable levels of cleanliness in the Containment and Drywell, thorough inspection and cleaning of these areas were performed. Individual fibers were not found in the Drywell or Containment during the pre-cleaning area inspections by Incident Response Team members, who were aware of the significance of the fibers and were specifically looking for their presence. Additionally, an insignificant amount of fibrous material was identified in the debris obtained by vacuum cleaning of the containment and drywell. These observations indicate that there is no chronic or acute degradation of properly installed filter media which would introduce discrete fibers into the suppression pool.

The above evidence leads to the conclusion that the material entered the suppression pool as intact pieces rather than individual fibers. Exposure to suppression pool conditions is believed to have broken down some pieces into individual fibers which were then collected as a mat on the strainer surfaces. It is believed that the roughing filter material was introduced to the suppression pool as a result of installation or maintenance activities.

The fouling of the strainers occurred over a period of several months, punctuated by limited cleaning efforts, discussed later in this report. The actual time the material entered the suppression pool cannot be determined.

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However, because suppression pool cooling operation causes significant turbulence in the pool, it has been postulated that roughing filter material may have been transported from the drywell side of the suppression pool to the containment side during the operation of suppression pool cooling associated with the March 26, 1993 reactor shutdown.

Suppression Pool Cleanliness and Maintenance Practices

Although repetitive tasks were in place for the periodic inspection of the suppression pool, corrective actions had been directed at the removal of discrete, bulky items, which had settled to the pool floor. Maintenance practices call for the immediate removal of items with positive or neutral buoyancy, which could potentially cause gross strainer fouling. Additionally, the RHR strainers were cleaned in 1989, during the first refueling outage. Corrosion products and other sedimentary deposits were not considered to be a threat to ECCS operability, based on the assumption that they would pass through the strainers unimpeded. The presence of fibrous material which could act as a fine filtration media for suspended particulates, was not identified or postulated prior to the recent events. As a result, thorough cleaning of the suppression pool had not been completed since the plant entered initial operation in 1986.

Inspection and cleaning of the suppression pool is controlled by periodic maintenance specified in the repetitive task program. The specific task identifies the cleanliness standard for the pool as ANSI N45.2 Cleanliness Class C. Such cleanliness standards are intended to be applied to piping and components, and are not easily adaptable to a large body such as the suppression pool. Although specific criteria identify both acceptable and unacceptable conditions, particle sizes which are acceptable under Class C (0.125 inches long) exceed the size of the strainer openings. Additionally, application of such criteria is subject to diverse interpretation. The problem is further compounded when inspection is done through a significant amount of water, or with remote video equipment (subject to distortion and magnification effects, when viewed on a two-dimensional display). Based on the above considerations, more effective measures are necessary for inspection and cleaning.

Until the complete inspection and cleaning of the suppression pool in April 1993, inspection and cleanup efforts were limited to easily visible and accessible pool areas. Because inspections were done from above the surface of the pool, the 120 horizontal vents between the drywell and containment were not inspected. Additionally, the area between the drywell wall and the suppression pool weir were not routinely inspected. The repetitive tasks neither specifically included nor excluded these areas from the inspection and cleaning requirements. However, the discovery of filter material and other debris in these areas indicates these areas were not inspected in the documented

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inspection activity. The disproportionate amount of debris found in these areas in April, after the pool was thought to have been cleaned in February, highlights the significance of these omissions.

The final factor in the consideration of suppression pool cleanliness programs is the lack of knowledge of plant staff regarding the effect of pool conditions on ECCS operability. Plant personnel involved in past inspection and cleanup activities for the pool did not recognize the potential compromise to system operability presented by the issues discussed in the preceding paragraphs. Conviction that the pool conditions were acceptable was reinforced by the following standards for operability:

- continued satisfactory results of ECCS system surveillance testing
- continued acceptable water clarity and chemistry conditions
- continued acceptable operation of the Suppression Pool Cleanup System
- procedural requirements for the periodic removal of known objects from the pool floor
- procedural requirements for the immediate removal of items with neutral or positive buoyancy when inadvertently introduced into the pool.

Cleanliness conditions and practices in the general areas of the containment and drywell were also evaluated. These considerations are especially significant for containment designs with an open suppression pool. The effect of containment spray and pool swell in accident scenarios could result in the transfer of debris from the higher elevations of the containment to the suppression pool. All of the analyses discussed above for the suppression pool can be equally applied to the drywell and containment.

In addition, the issue of material accountability was considered. Prior to these events, adequate material accountability requirements were not in place for material introduced into the containment. This policy allowed material to be left in these areas after it was brought in for specific activities, contributing to the general cleanliness problems in the containment, and increasing the probability of introducing foreign material into the suppression pool. The lack of an adequate accountability policy also contributed to the lack of sensitivity toward the effects of cleanliness on equipment operability.

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Evaluation of Design Adequacy

The original strainer design was evaluated to determine adequacy with respect to design requirements. The primary function of the strainer is to ensure that particles of a size detrimental to ECCS pump operation are restricted from the pump suction, while ensuring that the minimum Net Positive Suction Head requirements are not compromised under the most limiting conditions. The original design specifications required that the strainer provide no more than 1 psid head loss, at rated flow and fifty percent fouled conditions. The design of the strainer was evaluated and identified to satisfy the stated specification, provided that adequate cleanliness conditions were maintained in the suppression pool.

Another requirement of the strainer, although not specifically addressed in the design specifications, is that the design provide adequate structural strength to preclude failure which could introduce gross amounts of debris into the pump suction, adversely affecting operability. As in the previous discussion, assuming design flow and fifty percent fouling on the strainer, the strainer would not have been susceptible to failure as long as adequate pool cleanliness was maintained.

Although the design of the original strainers is adequate for the original design assumptions, excessive differential pressures were recorded, and deformation of the strainers was experienced, even though rated flow was able to be maintained. This indicates that although the design could be considered adequate, resistance to fouling, tolerance to fouling, and the margin to failure were minimal.

IV. Safety Analysis

Emergency Core Cooling Systems (ECCS) are designed to provide protection against a postulated LOCA caused by ruptures in primary system piping. The ECCS injection network is comprised of a high pressure core spray (HPCS) [BG] system, a low pressure core spray (LPCS) [BM] system and the low pressure coolant injection (LPCI) [BO] mode of the residual heat removal (RHR) System. An automatic depressurization system (ADS) also assists the injection network under certain conditions.

The design requirements of the RHR suction strainers is provided in the General Electric design specification. This design specification states that the strainer mesh openings shall be capable of effectively screening all foreign particles of sufficient size (>3/32 inch sphere) to clog the pump cyclone separators or containment spray nozzles. The suction strainer shall also be designed such that it does not become more than fifty percent plugged following one hundred days of post-LOCA operation. The differential pressure associated

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with a fifty percent plugged strainer is used in Net Positive Suction Head (NPSH) calculations to ensure that the minimum NPSH available exceeds the minimum NPSH for the pump.

At PNPP, a fifty percent plugged strainer of the original design corresponds to 1 psid at design flow (reference USAR 6.2.2.2). This differential pressure is a design input parameter used in calculating the NPSH available in accordance with Reg Guide 1.1 (reference USAR 5.4.7.2.2.a). The requirements for 1 psid for fifty percent blockage at design flow rate and 3/32 inch strainer mesh openings are also described in the Gilbert procurement specification. No criteria is specified for maximum approach velocity. Similar design requirements exist for the other suppression pool suction strainers.

Analysis of previous quarterly pump surveillance data revealed that the RHR A and B strainers have been operated with differential pressures in excess of 1 psid numerous times. It is expected that the strainers would have experienced fouling beyond the fifty percent blockage/1 psid design value during the 100 days of continuous operation following a LOCA event. Available data cannot be used to predict either the rate or maximum severity of the fouling, both of which greatly influence the operability of the RHR systems during a sustained event with continued pool circulation activities such as a Reactor Recirculation System line break accident. Because of this lack of predictability, a worst case scenario of inadequate pump NPSH may be possible. Assuming an NPSH inadequacy, the ability of the RHR A and B pumps to continue to operate through this postulated accident, without operator intervention, would eventually be compromised. The conservative conclusion is that the RHR system may not have performed its intended safety function of long-term continuous suction from the suppression pool following a postulated accident. This conservative conclusion encompasses past operations, from initial startup to March 26, 1993, when the plant was last shut down.

In summary, performance of the RHR pumps throughout a postulated LOCA may have previously been compromised. Therefore, this event was considered to be safety significant.

Generic Letter 91-18 Section 6.7 addresses use of manual action in place of automatic action in its detailed discussion of specific operability issues. Although the Section 6.7 discussion does not directly apply to the situation with the RHR suppression pool suction strainer foulings and the operability determination, some of the concepts included in the discussion are pertinent in considering operator mitigation of the degraded RHR systems.

Control room operators are expected to use their training and the assistance of the fully staffed Emergency Response Organization in the event of a postulated accident. Although RHR suction strainer fouling would not have been anticipated

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and there were no procedures in place to backflush the strainers or otherwise alleviate pump NPSH degradation as a result of such fouling, pump flow, discharge pressure, and motor amperage are monitored from the control room, and it is realistically expected that the operators would detect and react to degraded pump performance. Operators are fully trained to monitor and interpret the changes in pump parameters. It is realistically expected that the operators would assess and prioritize cooling requirements, take full advantage of available redundant equipment, and fully utilize the technical expertise available through the Emergency Response Organization to diagnose the problems and implement appropriate solutions to ensure adequate residual heat removal capabilities.

V. Corrective Action

To prevent recurrence, the following corrective actions have been/will be taken:

1. Containment, drywell, and the suppression pool were cleaned and will be inspected to the newly established criterion prior to startup.

2. Plant Administrative Procedure (PAP-0204) "Housekeeping/Cleanliness Control Program" will be modified to strengthen Containment/Drywell cleanliness requirements.

3. Improved inspection standards and surveillance techniques are being developed and will be implemented prior to startup to provide more appropriate indications of suppression pool cleanliness.

4. Roughing filters installed on Containment and Drywell Cooling Systems have been determined not to be necessary for power operations. To prevent inadvertent introduction of filter material into the suppression pool, design changes have been implemented to remove the filter material.

5. The suppression pool condition will be monitored during Technical Specification Surveillance runs of ECCS pumps, in suppression pool to suppression pool mode, by monitoring pump suction pressures. Surveillance data will then be compared against pre-established criteria. Moreover, appropriate defined corrective actions will then be initiated, based on the surveillance data. Additionally, applicable strainers will be visually inspected following their respective pump runs.

6. System Operating Instruction (SOI-E12) "Residual Heat Removal System" will also be revised to include monitoring of suction pressure during suppression pool to suppression pool modes of operation for RHR "A" and "B". Appropriate defined corrective actions will then be initiated, based on the observed data.

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7. To prevent the introduction of fibrous or plastic-type material into the containment/drywell as a result of design modification activities, Nuclear Engineering Instruction (NEI-0330) "Interface Reviews and Evaluation" is being revised to include a required interface for design modifications to ensure appropriate consideration of the use of such materials. This revision will be in effect prior to startup.

8. Plant Administrative Procedure (PAP-1102) "Plant Chemistry Control Program" is being revised to add an analysis parameter to the Suppression Pool Chemistry Log which will provide an indication of corrosion product build-up and the presence of fibrous material. This sampling and testing is performed weekly.

9. The repetitive task utilized every refueling outage for inspecting suppression pool cleanliness will be revised to ensure all portions of the suppression pool (including the drywell and the 120 horizontal vents between the drywell and containment) are inspected.

10. Integrated Operating Instruction (IOI-1) "Cold Startup" will be revised to require containment and drywell inspections by the Shift Supervisor (or higher) prior to startup.

11. A site-wide memorandum will be distributed which will identify the importance of eliminating foreign material in the suppression pool. This memorandum will also address plant cleanliness, and will provide for a non-discipline reporting process in situations where items are dropped into the suppression pool.

12. Training will be provided as part of Radiological Controls Training to further indoctrinate personnel to the necessity of maintaining containment/drywell and suppression pool cleanliness.

13. Although the design of the ECCS and RCIC strainers were considered to be adequate when appropriate cleanliness levels are maintained in the suppression pool, these strainers were redesigned to enhance safety margins. The new strainers will be installed prior to plant startup.

Energy Industry Identification System Codes are identified in the text as [XX].

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TITLE (4) Standby Diesel Generator 13 Failure to Start

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER 05000
01	20	93	93	-- 005 --	01	11	23	93	FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9): 1

POWER LEVEL (10): 95

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)	X	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Jairo Pinzon - Senior Engineer	(512) 972-8027

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
E	EK	DG	C634	YES					

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On January 20, 1993, Unit 1 was in Mode 1 at 95% power. Standby Diesel Generator 13 failed to start during a monthly surveillance, due to paint which had been applied to the fuel injection pumps. The paint ran into the fuel metering rod ports and caused binding of the fuel metering rods. The primary cause of this event was the lack of proper work process control. Contributing causes were inadequate implementation of lessons learned from industry operating experience and inadequate verbal communications which led to a lack of clearly defined responsibility for ensuring paint was not applied inappropriately. Corrective actions that have been or will be taken include revising work process control documents to include specific guidance on painting activities and pre-job briefings, enhancing the Operating Experience Review program, performing a case study of the event for training purposes, and including the event in the Licensed Operators Requalification Program. This event is also being reported as a valid failure of Standby Diesel Generator 13. The performance described herein clearly does not meet management's expectations. Efforts to improve station safety culture are ongoing.

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DESCRIPTION OF EVENT:

On January 20, 1993, Unit 1 was in Mode 1 at 95% power. Standby Diesel Generator (SDG) 13 failed to start during a scheduled monthly surveillance. Troubleshooting showed that paint which had been applied to the fuel injection pumps, ran into the fuel metering rod ports and caused binding of the fuel metering rods. The NRC was notified on January 20, 1993, at 2359 hours.

As part of the Material Condition Improvement Pilot Program, a contract for painting was awarded. At the request of the Pilot Program Leader (PPL) a work document was revised to paint SDG 13. The work document was revised by the planner on November 12, 1992, and signed by the Responsible Maintenance Authority on December 28, 1992.

On December 28, 1992, representatives from HL&P, the contractor Superintendent and contractor Foreman met to discuss the painting activities. Detailed directions were given by Maintenance on what was and what was not to be painted. The areas not to be painted centered on the fuel linkages. Instructions were given not to paint any labels, conduit, stainless steel, and shiny metal (alloys), or areas that had not been painted before.

The work request included an Operational Impact Assessment that required a Post Maintenance Test (PMT). This PMT, consisting of a start test, was written to "verify proper operation after coating is complete to ensure that the throttle linkage is not binding". The operations shift was told that the work would take approximately two to three weeks to complete. The operations shift thought there were two options for performing the start test, (1) declare the SDG inoperable every day that painting was performed and perform a start test at the end of the day to restore operability of the SDG or (2) declare the SDG inoperable for the duration of the painting and perform the start test at the end of that period. Neither option seemed viable, however, the operations shift agreed that the PMT was not necessary when told of the actions planned to ensure that paint would not be applied to inappropriate surfaces. These actions included a pre-job briefing with the HL&P representatives, the contractor Superintendent and the contractor Foreman. Additionally, the contractor was given direction to pick five of their best painters, who would be under the constant supervision of the contractor Foreman.

When management learned of the removal of the start test, the System Engineer was contacted to perform daily checks of the painting activities as an added precaution. Management intended that the System Engineer would be responsible for ensuring paint would not be applied inappropriately. The System Engineer did not understand that it was his responsibility for ensuring this happened.

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DESCRIPTION OF EVENT: (Cont'd)

Painting began on SDG 13 on December 29, 1992, and the majority of the work was completed within three days, followed by touch up of certain areas. The original prediction of two to three weeks was based on painting all components in the SDG room, not just the SDG.

A start of SDG 13 was attempted on January 20, 1993, as part of a scheduled monthly surveillance, and at 0627 hours SDG 13 was declared inoperable when it failed to start. The problem was traced to the fuel injection pumps. The fuel metering rods, which are connected to the throttle linkage, move in and out of the fuel injection pump. The fuel metering rod moves all the way through the pump, with a small portion exiting the inboard portion of the pump. The hole that the metering rod travels back and forth through, had paint obstructing the passage on 11 of the 20 pumps. The positioning of the pump is such that any extra paint on the body of the pump around the hole would allow paint to run into the hole and bind the metering rod. The affected fuel metering pumps were cleaned and lubricated. SDG 13 was returned to service on January 22, 1993, at 2101 hours.

CAUSE OF EVENT:

The primary cause of this event was lack of application of proper work process controls. The applicable painting procedure was inadequate, in that mandatory, in-process controls and maintenance tests were not required when painting safety-related components. An inappropriate decision to delete the PMT was made and the added precautions were inadequate. Additionally, the pre-job briefing was inadequate.

A contributing cause was inadequate implementation of lessons learned from industry operating experience. Although previous industry events of a similar nature had been reviewed as part of the station Operating Experience Review Program, the personnel involved in the painting were not fully cognizant of this experience and controls were insufficient to ensure cited corrective actions were implemented.

Other contributing causes were inadequate verbal communications which led to a lack of clearly defined responsibility for ensuring paint was not applied inappropriately.

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ANALYSIS OF EVENT:

SDG 13 was determined to have been inoperable from the time the painting began on December 29, 1992, until 2101 hours on January 22, 1993, (approximately 24 days) when the SDG was returned to service. Failure to restore SDG 13 to operable status within 72 hours is a violation of Technical Specification 3.8.1.1, Action b and therefore reportable pursuant to 10CFR50.73(a)(2)(i)(b). A subsequent review of the Operability Tracking Log (OTL) index showed that SDG 12 was inoperable for maintenance approximately 61 hours during the 24 days in which SDG 13 was inoperable. Failure to restore at least two SDGs to operable status within 2 hours is a violation of Technical Specification 3.8.1.1, Action f. The OTL index review also showed that during the 61 hours, some cross-train equipment was inoperable, and turbine-driven auxiliary feedwater (AFW) pump 14 was in a condition in which it may not have automatically started (ref: LER 93-007, Unit 1); this is a violation of Technical Specification 3.8.1.1, Action d. Additionally, Technical Specification 3.0.4 was violated because Unit 1 changed Modes three times while SDG 13 was inoperable. This event is also being reported as a valid failure of SDG 13 because SDG 13 failed to start during a scheduled monthly surveillance.

The SDG and AFW events were analyzed using the STP Probabilistic Safety Assessment (PSA), which has been reviewed by the NRC as documented in a Safety Evaluation Report dated January 21, 1992. The concurrent SDG and AFW unavailability is estimated to have negligibly changed the annual average core damage frequency from 4.4E-5/yr to 4.5E-5/yr.

The impact of SDGs 12 and 13, and AFW pump 14 being simultaneously unavailable is partially compensated for by STP's three-train safety design, with one train sufficient to mitigate most design basis accidents. The effects of this event on the following UFSAR Chapter 15 safety analyses were considered: loss-of-cooling accident (LOCA), main steam line break, feedwater line break, steam generator tube rupture, station blackout, anticipated transient without scram, and long-term cooling. The STP design has sufficient redundancy and margin to ensure that the acceptance limits for the above mentioned accidents would not be exceeded, with the exception of certain large break LOCAs.

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ANALYSIS OF EVENT: (Cont'd)

During a LOCA, one train of safety equipment is sufficient to ensure calculated results remain below the acceptance limits. The only exception is when a break occurs in the Reactor Coolant System cold leg with the operating Safety Injection (SI) train such that the required SI flow does not inject in to the reactor core. During the 61 hours in which SDGs 12 and 13 were coincidentally inoperable and AFW pump 14 potentially inoperable, the calculated results for this type of large break LOCA would have exceeded the acceptance limits. However, the STP PSA shows that this large-break LOCA coincident with a loss of offsite power (LOOP) is highly improbable. The NRC approved leak-before-break methodology also supports this conclusion. Hence, the actual safety significance is small due to the extremely low probability of the accidents.

CORRECTIVE ACTIONS:

1. The affected fuel metering rods were cleaned and lubricated. SDG 13 was run satisfactorily and returned to service on January 22, 1993, at 2101 hours.

2. The painting and coating procedure has been enhanced with respect to the pre-job briefing and PMT following painting.

3. The PMT Reference Manual has been revised to require post maintenance testing to be considered following maintenance involving painting or coatings.

4. The lessons learned from this event have been discussed with Senior Reactor Operators (SROs) assigned to both Units. Additionally, this event has been included in the Lessons Learned portion of the licensed Operator Requalification Training Program.

5. The Operating Experience Review program will continue to be enhanced per the STP Business Plan to ensure that lessons learned are translated into actions for the enhancement of plant safety and reliability.

6. HL&P has completed a case study of the SDG event for training purposes. The training has been presented to Shift Supervisors and Maintenance Planners in their continuing training programs and has also been presented to System Engineers.

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

ADDITIONAL INFORMATION:

Including this event, there had been one valid failure in the previous 20 valid tests and less than four valid failures in the previous 100 tests. Therefore, on January 20, 1993 the testing frequency was not changed from once per 31 days for SDG 13.

LER No. 498/93-007
South Texas Project Unit 1

NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
South Texas, Unit 1	05000 498	1 OF 11

TITLE (4) Technical Specification Required Shutdown due to the Inoperability of an Auxiliary Feedwater Pump

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
0 2	0 4	9 3	9 3	- 0 0 7 -	0 0	0 3	0 5	9 3	South Texas, Unit 2	05000 499
									FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9): 1

POWER LEVEL (10): 98

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Jairo Pinzon - Senior Engineer	(5 1 2) 9 7 2 - 8 0 2 7

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
E	BA	TUR	T147	Yes					

SUPPLEMENTAL REPORT EXPECTED (14)

			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On February 4, 1993, Unit 1 was in Mode 1 at 98% power. At 0937 hours, Unit 1 commenced a plant shutdown and an Unusual Event was declared due to the failure to return the Turbine Driven Auxiliary Feedwater Pump (TDAFWP) 14 to an operable status within the required Technical Specification allowed time. On February 1, 1993, during performance of a surveillance test, TDAFWP 14 tripped on overspeed. This resulted in the pump being declared inoperable and Unit 1 entering a 72 hour action statement. On February 3, 1993, Unit 2 experienced a reactor trip at which time TDAFWP 24 oversped and tripped. Since the 72 hour allowed time was due to expire soon and the cause of the Unit 2 overspeed had not been determined, Unit 1 was shutdown. The cause of the TDAFWP 14 overspeed events was water intrusion into the TDAFWP turbine adversely affecting performance. Corrective actions included extensive testing, analysis, and component examination to determine the causes of overspeed trips on TDAFWP 14 and TDAFWP 24.

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NRC FORM 366 (5-92)

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

DESCRIPTION OF EVENT:

Unit 1 Auxiliary Feedwater Pump

On February 4, 1993, Unit 1 was in Mode 1 at 98% power. At 0937 hours, Unit 1 commenced a plant shutdown and an Unusual Event was declared because Turbine Driven Auxiliary Feedwater Pump (TDAFWP) 14 was not returned to an operable status within the required Technical Specification allowed time.

After entry into Mode 3, as the fourth refueling outage was coming to an end, a surveillance was performed on TDAFWP with satisfactory results. Due to a problem encountered with control rod housing leakage, Unit 1 was cooled down for repairs. After the cooldown, the trip/throttle valve (MS-0514), which had been leaking prior to the outage, was disassembled for inspection and possible repair. The inspection revealed that the disc and seat had steam cuts. Repairs could not be effected because no replacement parts could be located. The valve was subsequently reassembled. Unit 1 entered Mode 3 at 0202 hours, on December 26, 1992. At 0102 hours the following morning, TDAFWP 14 oversped and tripped during a Post Maintenance Test (PMT) surveillance run. The operators used guidance provided in the AFW system operating procedure and performed a slow manual start of the pump. A successful surveillance was subsequently performed. During the investigation of this event, this surveillance was determined to be inadequate because of the manual start of the turbine. The pump and valve were declared operable following two more Motor Operated Valve Actuator Test (MOVATS) related starts. An Anticipated Transient Without Scram (ATWS) Mitigation System Actuation Circuitry (AMSAC) test was performed on December 31, 1992, without an overspeed occurrence. The AMSAC test is unlike the usual surveillance in that normally open MS-0143 is closed prior to the test. Since the stroke time of MS-0143 is greater than MS-0514, the result is a slower admission of steam to the TDAFWP than during a normal surveillance start.

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DESCRIPTION OF EVENT: (Con't)

The next TDAFWP 14 activity occurred on January 28, 1993, at 0600 hours. A number of activities were performed on TDAFWP 14 (pump and turbine) as part of a planned outage. On the same day, during a PMT surveillance run, TDAFWP 14 tripped on overspeed. On January 29, 1993, an attempt was made to perform a slow manual start of the pump. The turbine again tripped on overspeed.

Troubleshooting activities occurred on January 29, 1993, including contacting the governor vendor. The vendor arrived onsite on January 30, 1993, and determined that the governor valve was not closing completely. This finding corresponded to the symptoms of both the overspeed events and subsequent troubleshooting efforts. It was believed that the governor valve was misadjusted during the activities that took place on January 28, 1993. A number of successful starts were performed on January 30, 1993. At 1742 hours, on January 30, 1993, the surveillance for TDAFWP 14 was performed and successfully completed at 1905 hours. The pump was declared operable at 1908 hours.

On February 1, 1993, a surveillance test was performed at the request of the Unit 1 Operations Manager during which TDAFWP 14 tripped on overspeed. This resulted in the pump being declared inoperable and Unit 1 entering a 72 hour action statement. Extensive troubleshooting and evaluation ensued. On February 3, 1993, Unit 2 experienced a reactor trip during which TDAFWP 24 oversped and tripped (Unit 2 LER 93-004). The occurrence of this event coupled with previous Unit 1 overspeed events, resulted in the decision to shutdown Unit 1.

Unit 2 Auxiliary Feedwater Pump

On January 8, 1993, a successful surveillance on TDAFWP 24 was performed in which the pump started under normal service conditions. On January 23, 1993 Unit 2 experienced a reactor trip. The TDAFWP actuated and performed satisfactorily. Following the trip, operators attempted to secure the TDAFWP by using the control board trip pushbutton (electrical trip). This is not the normal method of closing MOV-0514 to secure the turbine.

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DESCRIPTION OF EVENT: (Con't)

Coincident with the trip, a mechanical overspeed indication was received in the control room. Investigation revealed that the mechanical overspeed trip device was actuated due to agitation caused by the electrical trip plunger. No physical overspeed condition actually occurred.

Activities on January 24th and 25th focused on correcting the above situation. On January 24th, several attempts to restart the pump resulted in a mechanical overspeed. The overspeed was believed to be due to moisture build up from closing MOV-0143. The TDAFWP was again started by locally opening MOV-0514. This was performed for water evacuation. The pump was then tripped from the control room. No mechanical overspeed trip annunciator was received and MOV-0514 reset normally. Maintenance troubleshooting discovered the mechanical trip linkage adjustment was too short. The TDAFWP was started locally and, when tripped from the control room, the mechanical overspeed trip device became unlatched. Two additional test runs of the TDAFWP 24 were initiated with no overspeed. On the 25th of January, the surveillance test for TDAFWP 24 was completed satisfactorily and the pump was declared operable.

Engineering contacted the valve manufacturer of MOV-0514 to discuss the situation. The problem with the overspeed linkage mechanism impact clearance was caused by a linkage pin diameter discrepancy wherein the actual pin size was 1/2" versus the 3/8" specified by the vendor. The manufacturer agreed to allow the impact clearance reduction in the linkage provided that the latch disengagement spring tension was increased to 30 lbs.

On January 30, 1993, TDAFWP 24 was again declared inoperable in order to verify the proper overspeed trip arm clearance and to obtain data on spring tension on the overspeed mechanism. Upon completion of two surveillance starts, the pump was declared operable.

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DESCRIPTION OF EVENT: (Con't)

A follow up call between Engineering and the valve manufacturer revealed that an impact gap of < 1/8" would be adequate. Engineering reevaluated the situation and decided that, although the short term spring adjustment would provide adequate prevention of unlatching problems, the long term corrective action should include modification of the slot length of the trip linkages on both units.

On February 3, 1993, Unit 2 tripped with an associated AFW actuation. TDAFWP 24 experienced an overspeed trip upon startup associated with the AFW actuation.

Investigation revealed that the above seat drain valve bypass (MS-217) was closed at the time of the overspeed event. Historical computer data was analyzed to determine when the valve position was changed subsequent to valve lineups being performed on April 15, 1992. This analysis determined that the Unit 2 above seat drain bypass had been out of position since a maintenance period between April 28, 1992 and April 29, 1992 allowing only marginal condensate drain flow. The valve stayed in that position, with slight leakage through it until January 24, 1993, when the Head Reactor Plant Operator verified the bypass being closed, causing a further reduction in drain flow. Further investigation of the valve lineup condition in Unit 2 revealed that the operators were not sure what the proper valve position should have been at the time that the overspeed event occurred.

CAUSE OF EVENT:

Unit 1

The cause of the TDAFWP 14 overspeed events was water intrusion into the TDAFWP turbine adversely affecting performance. The specific mechanism that precipitated the overspeed event is not known, however, it is believed that the causes are bounded by the following:

- Leakage through MOV-0514 valve
- Adverse effects of water accumulation in the governor valve
- Adverse effects of water accumulation in the turbine casing
- Coordination of trip/throttle valve stroke time and governor valve response capability.

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CAUSE OF EVENT: (Con't)

Unit 2

The cause of the Unit 2 overspeed event was water intrusion into the turbine from the upstream piping. Ineffective removal of condensate from the upstream steam supply piping has been attributed to the inappropriate closing of a steam trap bypass valve. The ineff' tive removal of condensed steam from the above seat drain of the :rip/throttle valve resulted in the presence of water in the steam supply line. The effect of this is a challenge to the capability of the governor control system. The overspeed trip linkage issues did not cause this overspeed trip.

ANALYSIS OF EVENT:

Based on the investigation, the Unit 1 TDAFWP was determined to be inoperable since the end of the Unit 1 fourth refueling outage. The Unit 2 TDAFWP was determined to be operable on January 30, 1993 by the successful completion of a monthly inservice test. It is speculated that some time between this date and February 3, 1993, the condensate buildup rendered the Unit 2 TDAFWP incapable of sustaining an automatic start without overspeeding and therefore, the pump was inoperable.

Completion of a plant shutdown required by Technical Specification is reportable pursuant to 10CFR50.73(a)(2)(i)(A). Operation with the TDAFWP inoperable for greater than 72 hours constituted an operation prohibited by Technical Specifications and is reportable pursuant to 10CFR50.73(a)(2)(i)(B).

The Auxiliary Feedwater (AFW) System at the South Texas Project (STP) is an Engineered Safety Feature (ESF). Its purpose is to provide cooling flow to each of the four steam generators immediately following a transient or an accident to remove decay heat. The system is comprised of four mechanically and electrically independent trains, each providing flow to a dedicated steam generator, three of which include a motor driven pump (MDP) and the fourth a turbine driven pump (TDP). This concept provides diversity and, therefore, reduces the potential for common mode failure. The turbine driven pump also provides cooling in the event of a station blackout (SBO) when in modes 1,2 or 3.

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ANALYSIS OF EVENT: (Con't)

An important aspect of the subject events with regard to safety impact is the fact that overspeed conditions did not adversely affect the functionality of the TDAFWP. The conditions experienced by each TDAFWP (one on each STP unit) would adversely impact the operability of that pump in that there is no assurance that the pump would start and run as the result of an automatic actuation. However, the problems encountered did not preclude the pump from being started and run as the result of reasonable operator action and therefore fulfilling its safety function with a high degree of confidence.

The safety analysis assumes that for design basis accidents (Chapter 15 of the STP Updated Final Safety Analysis Report (UFSAR)), a limiting single failure will occur. For accidents that require the operation of the AFW system, the limiting single failure is in the ESF actuation logic that initiates auxiliary feedwater flow. The UFSAR Section 15 Safety Analysis assumes that two AFW pumps operate. The configuration of AFW at STP has ESF Actuation Train A starting AFW trains 1 and 4 (train 4 includes the TDAFWP), ESF Train B starting AFW train 2, and ESF Train C starting AFW train 3. With AFW train 4 out of service, a minimum of two AFW trains would still be operable after any single failure. Therefore, the results of the UFSAR Section 15 safety analysis are not impacted with AFW train 4 not available.

The AFW system is also used to mitigate the Anticipated Transient Without Scram (ATWS) initiating event. The Solid State Protection System (SSPS) and Engineered Safety Features Actuation System (ESFAS) serve to provide actuation signals to the AFW system should an ATWS initiating event occur. Additionally, both operator action and the ATWS Mitigating System Actuation Circuitry (AMSAC) serve as recovery and backup sources of AFW system actuation signals. The STP Level 2 Probabilistic Safety Assessment ("L2 PSA") does not take credit for AMSAC and shows that the frequency of an ATWS event at STP is insignificant. In the very unlikely event of an ATWS, loss of the TDAFWP due to an overspeed trip would still leave three pumps to mitigate the event.

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ANALYSIS OF EVENT: (Con't)

Cold shutdown capability of STP has been evaluated to demonstrate that the units can achieve cold shutdown conditions following a Safe Shutdown Earthquake (SSE) assuming a single failure and the loss of offsite power (LOOP). The AFW system is an integral part of that capability. Assuming that the TDAFWP is lost due to an overspeed condition and an additional train is lost due to a single failure then two trains of AFW remain to ensure that cold shutdown is reached. Two trains of AFW will provide decay heat removal while assuring that the pressurizer does not go water-solid, and one train of AFW delivered to one steam generator will assure decay heat removal but the pressurizer may go water solid. Also note that in the event of a fire affecting a single safety train, STP has single train shutdown capability, thus providing redundant shutdown capability of the remaining two trains.

The most important function considered for the TDAFWP is its role in mitigating the Station Black Out (SBO) event. The SBO event includes the provision for an Alternate Alternating Current (AAC) source. This source is the Train B Standby Diesel Generator (SDG). This emergency AC source provides power to it's associated train components as well as providing backfeed capability to either the Train A or C centrifugal charging pump (CCP) and Class 1E battery charger. As a result, the SBO analysis assumes that two AFW trains, Train B and Train D (the TDAFWP) will be available to mitigate the blackout with no cross-connecting (i.e., no operator action) required. If it is assumed that the TDAFWP is not available, then the one train of AFW is still adequate in terms of cooling flow. However, to ensure that the heat transfer rate from the Reactor Coolant System (RCS) is sufficient, it is necessary to cross-connect and provide flow to an additional steam generator. This will require operator action. Since the time frames involved are relatively long (~47 minutes, steam generator dry out time), the operator action to cross-connect one or more steam generators can be performed before the affected steam generator becomes dry. It can also be expected that, given the failure modes seen with the TDAFWP, there is a high probability that the pump can be returned to service following an overspeed trip, as was demonstrated by the subject events. Note that the L2 PSA, which the NRC has reviewed and has accepted for safety evaluations (e.g., technical specification evaluations, waivers of compliance, etc.), assumes that one train of AFW to one steam generator, as discussed above, will provide adequate decay heat removal but not necessarily prevent the pressurizer from going water-solid.

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CORRECTIVE ACTIONS:

The following actions have been taken or will be taken to address the Unit 1 and Unit 2 events and generic implications.

1. Both Units' trip/throttle valves and governors were sent to representative vendors for complete refurbishment and testing. The gearing arrangement of the trip/throttle valve was modified to ensure slower stroke time thus enabling a more positive governor response. Additionally, the governor valves were reworked. The governor valve stems were replaced.

2. A review of the generic implications associated with the blockage of the Unit 1 TDAFWP exhaust drain has been conducted. Both units exhaust drains have been inspected for the presence of foreign material. Other safety related equipment in the area was inspected for possible foreign material intrusion, with no adverse findings. A sample of the foreign material was analyzed and determined to be the result of sand blasting operations. Additionally, the Unit 1 orificed cap was removed from the turbine exhaust drain line. (Unit 2 did not have an orificed cap installed).

3. A modification to the TDAFWP drain system was implemented to remove the steam traps in the steam line drain system, replacing it with a spool piece.

4. The trip/throttle valve high pressure stem leakoff was separated from the turbine casing and rerouted to the sump to prevent possible steam intrusion into the turbine casing.

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CORRECTIVE ACTIONS: (Con't)

5. Operating procedures identified as deficient during the review have been changed to reflect present system design and operability considerations. Operator logs were also changed to monitor the above seat drains. Deficient field labeling was removed.

6. Enhanced testing will be conducted prior to declaring the TDAFWP operable. Testing will include:

   - Verification of the drain system operation
   - Verification of the proper operation of the trip/throttle valve
   - Verification of governor valve operation
   - Verification of the trip /throttle valve linkage, overspeed linkage and governor valve interface.

   This testing has been completed in Unit 2 and will be completed in Unit 1 prior to Unit 1 entering Mode 2.

7. Maintenance training and procedures will be reviewed for the inclusion of vendor requirements and other enhancements. This review will be completed and a Plan of Action developed by April 15, 1993. HL&P will use the equipment vendors for maintenance of the TDAFWP trip/throttle valves, governor valves and associated control linkages until appropriate procedure enhancements and training is conducted.

8. HL&P will develop a program to monitor MOV-0514 leakage. This program will be developed by June 30, 1993.

9. An augmented surveillance testing program has been developed to ensure that the corrective actions have in fact addressed the overspeed causes.

10. HL&P has performed a verification of system lineups and adequate drainage systems. This verification has been performed to ensure that the steam line supply to the TDAFWP is optimized in terms of condensate removal. Based on this verification HL&P will evaluate additional design changes by April 15, 1993.

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

CORRECTIVE ACTIONS: (Con't)

11. HL&P will perform an evaluation to determine the cause of the pitting of the governor valve stem. Corrective actions will be developed as necessary. This evaluation will be completed by April 30, 1993.

Although not a specific corrective action, the following actions were taken by HL&P with respect to this event

1. Quality Assurance performed an in depth review of AFW procedure, work documentation, preventive maintenance, and industry events to determine the adequacy of the HL&P program with respect to AFW system operation and maintenance.

2. The Nuclear Safety Review Board (NSRB) reviewed the investigation to determine the adequacy of the root cause findings.

3. The Plant Operations Review Committee (PORC) reviewed and approved the enhanced testing procedure.

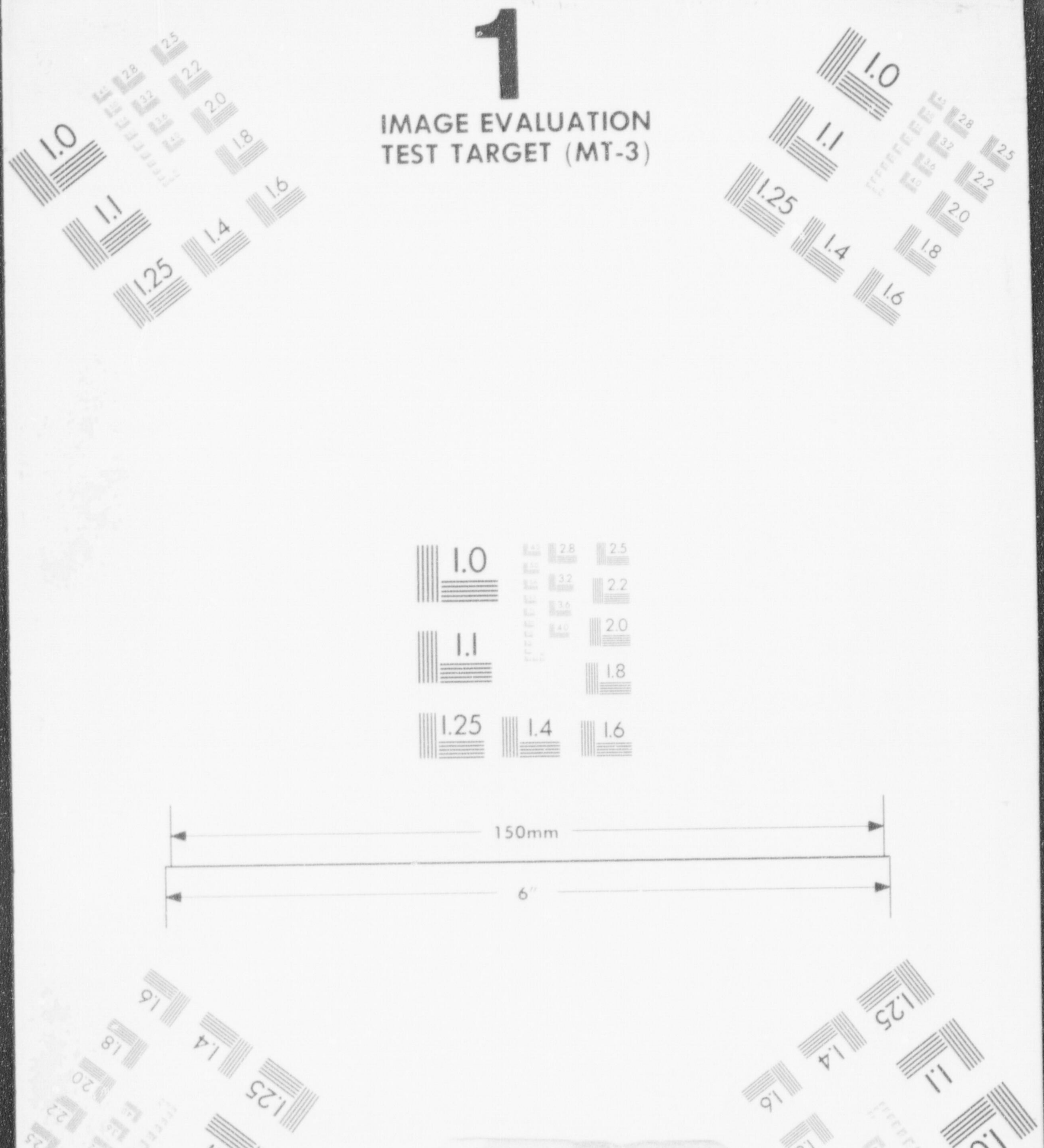
4. Sargeant & Lundy was retained to perform an independent review of the root causes and proposed corrective actions developed by HL&P. Their findings were consistent with HL&P's.

ADDITIONAL INFORMATION:

In the past two years there have been no similar events regarding a Technical Specification required shutdown due to the inoperability of the TDAFWP. Unit 2 LER 93-004 documents a reactor trip in which the Unit 2 TDAFWP also tripped on overspeed.

NRC FORM 366A (5-92) LER\93062001.U1

LER No. 529/93-001
Palo Verde Unit 2


1
IMAGE EVALUATION
TEST TARGET (MT-3)
1.0
1.1
1.25
1.4
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2.0
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IMAGE EVALUATION
TEST TARGET (MT-3)

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IMAGE EVALUATION TEST TARGET (MT-3)

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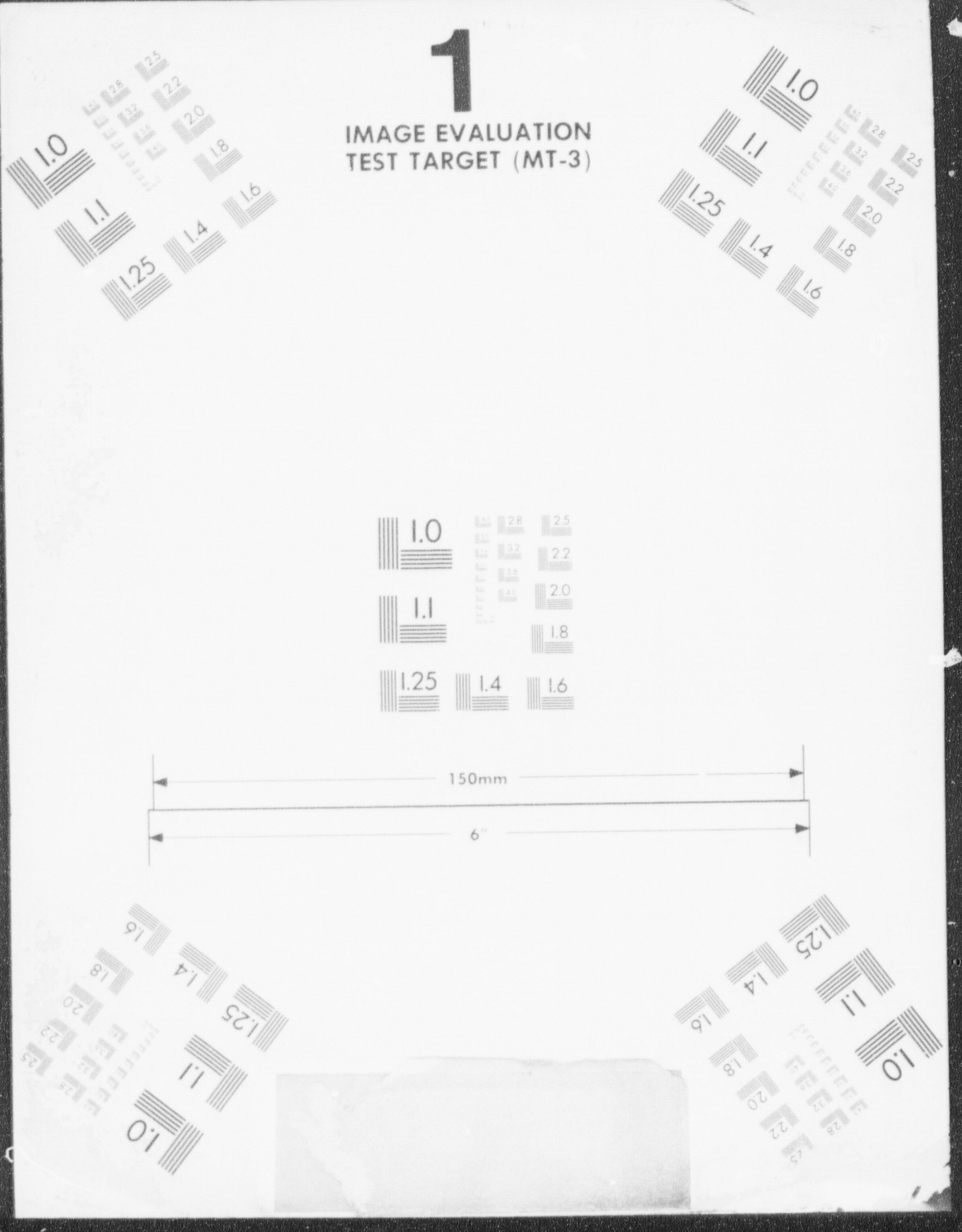
1
IMAGE EVALUATION
TEST TARGET (MT-3)
150mm
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TITLE (4): Manual Reactor Trip Following a Steam Generator T... Rupture

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
									N/A	0 5 0 0 0
0 3	1 4	9 3	9 3	0 0 1	0 2	0 8	1 4	9 3	N/A	0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 0 9 8

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

[ ]	20.402(b)	[ ]	20.405(c)	[X]	50.73(a)(2)(iv)	[ ]	73.71(b)
[ ]	20.405(a)(1)(i)	[ ]	50.36(c)(1)	[ ]	50.73(a)(2)(v)	[ ]	73.71(c)
[ ]	20.405(a)(1)(ii)	[ ]	50.36(c)(2)	[ ]	50.73(a)(2)(vii)	[X]	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
[ ]	20.405(a)(1)(iii)	[X]	50.73(a)(2)(i)	[ ]	50.73(a)(2)(viii)(A)		Special Report
[ ]	20.405(a)(1)(iv)	[X]	50.73(a)(2)(ii)	[ ]	50.73(a)(2)(viii)(B)		
[ ]	20.405(a)(1)(v)	[ ]	50.73(a)(2)(iii)	[ ]	50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
Thomas R. Bradish, Manager, Nuclear Regulatory Affairs	6 0 2 3 9 3 - 5 4 2 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[X] NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On March 14, 1993, at approximately 0434 MST, Palo Verde Unit 2 was in Mode 1 (POWER OPERATION), operating at approximately 98 percent power when a steam generator tube ruptured in Steam Generator 2. At approximately 0447 MST, the reactor was manually tripped due to low pressurizer level and pressure. Approximately 22 seconds later, valid accuations of the Safety Injection Actuation System (SIAS) and the Containment Isolation Actuation System (CIAS) occurred due to low pressurizer pressure. Pressurizer level was restored and a controlled cooldown and depressurization of the Reactor Coolant System (RCS) was conducted in accordance with approved procedures. A steam generator tube rupture in Steam Generator 2 was diagnosed, and the steam generator was successfully isolated.

This event was investigated in accordance with the PVNGS Incident Investigation Program. The rupture of the steam generator tube was due to intergranular attack/intergranular stress corrosion cracking (IGA/IGSCC) which occurred as a result of tube-to-tube crevice formation. The cause of the SIAS and CIAS was the loss of RCS inventory and the contraction of the RCS upon reactor trip. Pursuant to Technical Specifications 3.5.2, ACTION b, this LER also provides the Special Report required for an Emergency Core Cooling System actuation.

There have been no previous similar events reported pursuant to 10CFR50.73.

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TEXT

I. DESCRIPTION OF WHAT OCCURRED:

A. Initial Conditions:

At 0434 MST on March 14, 1993, Palo Verde Unit 2 was in Mode 1 (POWER OPERATION) at approximately 98 percent power.

B. Reportable Event Description (Including Dates and Approximate Times of Major Occurrences):

Event Classification: The completion of any nuclear plant shutdown required by Technical Specifications;

an event or condition that resulted in a principal safety barrier being seriously degraded; and

an event that resulted in an automatic actuation of an Engineered Safety Feature (ESF)(JE) and the Reactor Protection System (RPS)(JE).

At approximately 0434 MST on March 14, 1993, Palo Verde Unit 2 experienced a steam generator tube rupture in Steam Generator 2 (AB). At approximately 0447 MST, the reactor (AC) was manually tripped due to low pressurizer (AB) level and pressure. Approximately 22 seconds later, valid Engineered Safety Feature Actuation System (ESFAS) actuations of the Safety Injection Actuation System (SIAS) (JI)(BP) and the Containment Isolation Actuation System (CIAS) (JI)(BD) occurred due to low pressurizer pressure. Pressurizer level was restored and a controlled cooldown and depressurization of the Reactor Coolant System (RCS) (AB) was conducted in accordance with approved procedures. A steam generator tube rupture in Steam Generator 2 was diagnosed, and the steam generator was successfully isolated.

Prior to the event, in July, 1992, Unit 2 began measuring detectable levels of tritium at a level of 1.0 E-5 microCurie/gram (μCi/gm) in the secondary system. No other nuclides typically present in primary-to-secondary leakage, such as iodine and xenon, were detected. The initial leak rate was determined to be approximately 1 gallon per day (gpd). A Chemistry Action Document (CAD) was initiated to monitor the Steam Generator 1 Blowdown Radiation Monitor (RU-4) (IL)(MON), Steam Generator 2 Blowdown Radiation Monitor (RU-5) (IL)(MON), and the Condenser Vacuum Exhaust Radiation Monitor (RU-141) (IL)(MON) every 4 hours to

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TEXT

trend potential increases in activity. Trend information was logged in the Unit 2 Radiation Monitoring System (RMS)/Effluent Shift Log. On February 3, 1993, RU-5 indicated activity above background in the Steam Generator 2 (AB)(SG) blowdown line. On February 4, 1993, RU-4 and RU-5 setpoints were lowered, in accordance with procedures, to more closely monitor potential increases in leakage. On February 20, 1993, Iodine-131 was detected in Steam Generator 2 blowdown at a concentration of approximately 3.0 E-8 μCi/gm. Iodine-131 activity trends increased from 3.0 E-8 μCi/gm to 1.0 E-7 μCi/gm between February 20 and February 27, 1993. RU-4 and RU-5 also exhibited trend increases. On February 28, 1993, a CAD was issued to increase the monitoring of RU-4, RU-5, and RU-141 to every 2 hours. RU-4 and RU-5 setpoints were periodically adjusted in accordance with procedures, to closely monitor increases and decreases in activity levels. On March 3, 1993, Chemistry personnel (utility-nonlicensed) began using Iodine-131 activity levels to calculate the steam generator leak rate. Initial Iodine-131 leak rate calculations indicated a leak of approximately 8 gpd. From March 9 to March 13, 1993, the leak rate calculation indicated a steady leak of approximately 10 gpd. [NOTE: Post event calculations using tritium leak rate data indicate that the actual leak rate during this time period was approximately 20 gpd.]

On the morning of March 14, 1993, at approximately 0025 MST, the Gas Stripper (CA)(DGS) was placed in service to de-gas the Reactor Coolant System (RCS) (AB) in preparation for the upcoming refueling outage. Placing the Gas Stripper into service caused an anticipated boration of the RCS, resulting in a slight drop (approximately 0.75 degree Fahrenheit) in RCS average temperature (Tave). Control Room (NA) personnel (utility-licensed) responded to the slow temperature decrease by diluting the Volume Control Tank (VCT) (CA)(TK) and placing the deborating ion exchanger into service. The decrease in RCS Tave caused pressurizer level to drop approximately 0.5 percent over a three-hour period.

At approximately 0434 MST, Control Room personnel observed a notable decrease in pressurizer (AB)(PZR) level and pressure. Control Room personnel suspected that a leak in the Gas Stripper was causing the decrease in pressurizer level. The Gas Stripper, which is not normally in operation, had been recently placed in service to support the upcoming Unit 2 refueling outage. Concurrently, an alarm (IB)(ALM) was received on the Steam Generator 2 Main Steam Line Radiation Monitor (RU-140) (IL)(MON), Channel A. The RU-140 alarm was acknowledged and announced in the Control Room.

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TEXT

At approximately 0436 MST, Control Room personnel started a third charging pump (CB)(P) and energized the pressurizer back-up heaters (AB)(EHTR) in order to recover pressurizer level and pressure. At this time, the Nuclear Cooling Water Radiation Monitor (RU-6) (IL)(MON) alarmed and cleared. Control Room personnel performed a check of the Containment Building (NH) parameters (i.e., pressure, sump levels, temperature, and humidity) to determine if there was a leak inside Containment. Control Room personnel suspected there may have been a slight increase in Containment Building pressure but were unable to confirm their suspicion.

At approximately 0438 MST, an alarm was received on the Auxiliary Steam Condensate Receiver Tank Radiation Monitor (RU-7) (IL)(MON). The alarm was acknowledged and announced in the Control Room. This alarm supported operator suspicion of a Gas Stripper leak.

At approximately 0440 MST, Control Room personnel isolated letdown flow. The Control Room Supervisor (CRS) (utility-licensed) suggested a manual reactor (AB)(RCT) trip, but the Shift Supervisor (SS) (utility-licensed) felt the isolation of letdown might have slowed the rate of decrease in the pressurizer level and elected to wait to see if the level would recover. Control Room personnel displayed a histogram of radiation monitors which are associated with a steam generator tube rupture (SGTR) on the RMS (IL). The RMS showed that only RU-140 and RU-7 were in alarm. The Unit 2 RMS technician (utility-nonlicensed) was notified by a Control Room operator of the alarms on RU-140, Channels A and B. The RMS technician notified Radiation Protection personnel (utility and contractor-nonlicensed) and proceeded to the effluent office to check trends on RU-4, RU-5 and RU-140.

During this period, pressurizer level and RCS pressure continued to decrease. To preclude the possibility of a radiation release into the atmosphere, Control Room personnel removed Steam Bypass Control System (SBCS) Valves 1007 (JI)(V) and 1008 (JI)(V) from service and disabled the condensate draw-off controller (KA)(LCV). These actions were taken because SBCS Valves 1007 and 1008 relieve directly into the atmosphere and the draw-off could result in contamination of the Condensate Storage Tank (KA)(TK). Concurrent to removing the 2 SBCS valves from service, SBCS Valve 1003 (JI)(V) was returned to service to compensate, in part, for removal of the valves that relieve to the atmosphere. At approximately 0441 MST, RU-140, Channel B alarmed again, and went in and out of high alarm repeatedly. The CRS conducted a briefing with Control Room personnel and discussed actions to be taken in the event of a steam generator tube leak.

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TEXT

At approximately 0447 MST, the pressurizer heaters de-energized due to a pressurizer low level of 26 percent, and the SS directed a manual trip of the reactor. The main turbine (TA)(TRB) tripped as a result of the manual reactor trip. Primary system pressure decreased below the low pressurizer pressure Engineered Safety Feature Actuation System (ESFAS) (JE) setpoint of 1837 pounds per square inch absolute (psia) due to the loss of RCS inventory and the contraction of the RCS due to a decrease in RCS temperature upon reactor trip. Valid actuations of the Safety Injection Actuation System (SIAS) (JE) and Containment Isolation Actuation System (CIAS) (JE) were received 22 seconds after the reactor trip due to low pressurizer pressure. Pressurizer level indicated below zero percent level and pressurizer pressure decreased to 1677 psia. High Pressure Safety Injection (HPSI) (P)(BQ) restored pressurizer level to approximately 4 percent and pressurizer pressure to approximately 1880 psia. Control Room personnel stopped Reactor Coolant Pumps (RCP) 1B and 2B (AB)(P). RCP 1B pressurizer spray valve (AB)(V) was out-of-service so this combination of RCPs was selected to maintain pressurizer spray capability.

The RMS technician monitored activities until Control Room personnel manually tripped the reactor. The RMS technician informed the Chemistry technician of the alarms received on RU-140. The RMS technician was concerned with a potential steam release and requested that the Chemistry technician obtain main steam samples for analysis. The RU-140 alarms cleared shortly after the reactor trip.

All safety systems functioned as required. Following the SIAS, the combined makeup from the HPSI and charging pumps slowly increased pressurizer level. Pressurizer pressure was maintained at approximately 1872 psia until a plant cooldown and depressurization was initiated.

The Palo Verde Nuclear Generating Station (PVNGS) Emergency Plan Implementing Procedure, "Emergency Classification," (EPIP-02) required the declaration of a Notification of Unusual Event (NUE) for an event resulting in a SIAS actuation caused by a valid low pressurizer pressure condition. At approximately 0458 MST, the SS declared an NUE due to the valid SIAS actuation. At approximately 0502 MST, the emergency classification was upgraded to an Alert, due to RCS leakage in excess of 44 gallons per minute (gpm). At the time the emergency classification was determined, Control Room HPSI flow indication was zero, letdown flow was isolated, 3 charging pumps were in operation, and pressurizer level appeared to be increasing slowly. This indicated to the SS that the leak was within the capacity of the 3 charging pumps.

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TEXT

Post-event calculations indicated that actual RCS leak rate was approximately 240 gpm, which is in excess of charging pump capacity, for a period of approximately seven minutes immediately prior to the reactor trip. When plant parameters were reviewed following the reactor trip, pressurizer level had been restored and was increasing with three charging pumps running and no indication of HPSI flow. Under the conditions observed after the trip, the RCS leak rate was not perceived to be in excess of charging pump capacity and the RCS inventory loss was under control.

The CRS, using the Emergency Operations Procedure Diagnostic Logic Tree (DLT), diagnosed a reactor trip because plant conditions did not allow the diagnosis for a specific optimum recovery procedure. However, the entry conditions for the reactor trip recovery procedure could not be met because pressurizer level was not greater than 10 percent. The SS directed the CRS to re-diagnose the event but, as before, the diagnosis was that of a reactor trip and entry conditions were still not satisfied. At approximately 0502 MST, the CRS entered the Functional Recovery Procedure (FRP) due to inconclusive diagnosis using the DLT.

Although Control Room personnel suspected a SGTR, the diagnosis was not made immediately because the DLT used a "snap-shot" philosophy (i.e., what is occurring at the specific time of observation). This philosophy does not direct the operator to consider previous trends or alarms. Also, the RMS response to the event was confusing to Control Room personnel and it was not clear why the RU-140 alarms were received. The RU-140 alarms did not act in a manner consistent with the simulator display during training exercises. In simulator scenarios, RU-140 does not alarm until late in the event and the alarms remain throughout the event. It was further confusing to Control Room personnel that the primary indicator alarms for a SGTR (RU-4, RU-5, and RU-141) were not present. Radiation Monitors RU-4 and RU-5 had low flow indications because they were isolated upon the SIAS actuation. These three alarms are used as indicators of a SGTR event.

The FRP directed Control Room personnel to align charging pump suction directly to the Refueling Water Tank (BP)(TK) and close the VCT outlet. After Control Room personnel performed this function the "E" charging pump (CB)(P) tripped on low suction pressure. The operators aligned charging for an alternate boration flow path per the FRP, and restarted charging pump "E".

At approximately 0520 MST, Control Room personnel restored RU-4 and RU-5, which had been isolated by the SIAS, as directed by the FRP. At approximately 0529 MST, RU-5 reached the alert and high

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TEXT

alarm setpoints, and at approximately 0531 MST, RU-141 reached its alert setpoint. Control Room personnel then had positive confirmation of a SGTR in Steam Generator 2.

Following the reactor trip, the crew had shifted the condenser post-filter blower (SH)(BLO) into the through-filter mode per the Steam Generator Tube Leak Abnormal Operating Procedure. The crew later reported that they felt the event was being mitigated because the release was minimized by the condenser exhaust filter (SH)(FLT).

The Nuclear Regulatory Commission Operations Center was notified of the event at approximately 0530 MST. The Emergency Response Data System (IB) was activated by Control Room personnel at approximately 0614 MST.

The CRS continued through the FRP, directing the crew to realign various systems into normal shutdown lineups. It was the CRS's intention to proceed through the FRP until RCS depressurization was directed and then once depressurized, use HPSI injection to restore pressurizer level. Once pressurizer level was restored to above 33 percent, the Pressure and Inventory Control Safety Function success criteria would allow the FRP to be exited and a re-diagnosis into the SGTR Procedure to be completed. This strategy would succeed in isolating the SGTR, but it is different than the SGTR strategy that is designed into the FRP. In the FRP, it is assumed that the CRS finds indications of an SGTR at Step 3.21, and then performs the steps in an attachment which are similar to the isolation and depressurization steps in the recovery procedure for a SGTR.

Control Room personnel continued recovery actions per the FRP to restore pressurizer level to greater than 33 percent. At approximately 0604 MST, the CRS directed an RCS cooldown to 545 degrees Fahrenheit and a depressurization to 1500 psia. HPSI injection increased as the RCS depressurized. Pressurizer level was restored to 33 percent and Control Room personnel stabilized RCS pressure and temperature. The acceptance criteria for the Pressure and Inventory Control Safety Function success path were met and at approximately 0624 MST, the CRS exited the FRP, again performed the DLT, and diagnosed an SGTR. The SGTR Recovery Procedure was entered at approximately 0645 MST. The SS then directed that crew turnover commence. At approximately 0721 MST, the RCS cooldown was restarted per the SGTR procedure, and at approximately 0728 MST, Steam Generator 2 was isolated.

The Pressurized Thermal Shock limit of 200 degrees Fahrenheit subcooled margin was approached during RCS depressurization and

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TEXT

cooldown. Isolated Steam Generator 2 pressure remained fairly constant and the RCS pressure was being maintained above the isolated steam generator pressure. Steam Generator 2 was cooled down by allowing Steam Generator 2 pressure to exceed RCS pressure, thus back-flowing from the steam generator into the RCS. This allowed the ruptured steam generator to be cooled by a series of auxiliary feedwater additions. Chemistry samples were taken to ensure that RCS boron and chemistry limits would not be exceeded during this evolution.

At approximately 1029 MST, on March 14, 1993, Unit 2 entered Mode 4 (HOT SHUTDOWN). At approximately 1137 MST, following verification of proper safety system actuation, the SIAS and CIAS signals were reset. At approximately 1637 MST, the SGTR Recovery Procedure was exited.

At approximately 2235 MST, Shutdown Cooling (BP) Train A was placed in service.

At approximately 0556 MST, on March 15, 1993, Unit 2 entered Mode 5 (COLD SHUTDOWN).

The requirement of Technical Specification 3.4.5.2, Action b, for a primary-to-secondary leak which is greater than 720 gpd through any one steam generator was met (i.e., reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours).

The Alert was terminated at approximately 0115 MST, on March 15, 1993.

Unit 2 is currently in a scheduled refueling outage.

C. Status of structures, systems, or components that were inoperable at the start of the event that contributed to the event:

In addition to the SGTR described in Section I.B., RU-141 had an undetected equipment failure that caused it to read approximately 6 times less than grab sample activity. The monitor would have reached the alert alarm setpoint during the event at approximately 0456 MST, on March 14, 1993, if it had been indicating properly.

D. Cause of each component or system failure, if known:

A Steam Generator Tube Rupture Task Force of specialized APS personnel as well as industry consultants was formed to perform an equipment root cause of failure analysis. The task force

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TEXT

assembled a flow chart of possible failure modes to develop action plans for eddy current testing, tube pull selection, engineering analysis, and laboratory techniques. Using the information obtained from these activities, the task force concluded that the rupture of the steam generator tube was due to intergranular attack/intergranular stress corrosion cracking (IGA/IGSCC) which occurred as a result of tube-to-tube crevice formation. Several additional contributing factors such as increased sulfate levels due to resin intrusion, likelihood of cold working due to surface scratches, a less than standard microstructure in the ruptured tube, and increased susceptibility of contaminant concentration in the upper region of the tube bundle were also identified by the task force. The Steam Generator Tube Rupture Analysis Report was submitted by letter 102-02569, dated July 18, 1993, from W. F. Conway to the NRC. This report includes the event description and safety assessment, the steam generator design, operating history, analytical studies, and inspection, tube examination results, root cause of failure, Regulatory Guide 1.121 evaluation, recovery plan and corrective actions, and the basis for the restart of Unit 2 following the scheduled refueling outage. In response to a request by the NRC, additional information concerning the above Steam Generator Tube Rupture Analysis Report was submitted by letter 102-02593, dated July 30, 1993, from W. F. Conway to the NRC.

An equipment root cause of failure analysis (ERCFA) was performed for RU-141 under the PVNGS Incident Investigation Program. RU-141 has been subject to operability problems associated with moisture in the condenser air removal system (CARS). The effluent stream from the CARS is a high humidity air stream which during sampling condenses in the particulate filter and gas detector of RU-141. Previous commitments have been made to the NRC to resolve the moisture problem affecting the operability of RU-141. As a result, heat tracing and other temporary modifications were installed to improve operability. During the ERCFA, moisture was not found when the detector was removed from the sample chamber. The scintillation crystal was removed and found to be deteriorated (i.e., distorted and yellowed). In addition, the photo multiplier tube was found to have aged. The ERCFA determined that the reduced sensitivity of RU-141 was caused by the tube aging and the crystal deterioration which had resulted from elevated temperature conditions from the heat tracing. Although the heat tracing was within manufacturer's limits, the elevated temperatures caused the aging and deterioration. The reduction in sensitivity caused RU-141 to under-respond by a factor of 6 times the grab sample activity.

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E. Failure mode, mechanism, and effect of each failed component, if known:

As discussed in the correspondence to the NRC, the failure mechanism leading to the steam generator tube rupture was due to IGA/IGSCC which occurred as a result of tube-to-tube crevice formation. The crevice, together with the consequential heat flux, led to an aggresssive environment under a tenacious ridge deposit. As a consequence, a long deep crack, initiating under the ridge deposit, led to the loss of structural integrity under normal operating conditions.

The failure mode, mechanism, and effect of RU-141 are discussed in the previous section.

F. For failures of components with multiple functions, list of systems or secondary functions that were also affected:

Not applicable - no secondary functions were affected as a result of the component failures. Since activity calculations for effluent release permits are based on monitor to grab sample ratios rather than specific readings, and RU-141 trends indicated increasing activity, the factor of 6 difference does not affect effluent release permit calculations. Therefore, there are no effects on effluent release permit calculations associated with releases via the condenser exhaust. Additionally, there was no adverse effect on the High Range Condenser Exhaust Radiation Monitor (RU-142) (IL)(MON). Although the 2 monitors work in parallel to provide 11 decades of monitoring and indication, there is a decade overlap such that RU-142 would have alarmed as required.

G. For a failure that rendered a train of a safety system inoperable, estimated time elapsed from the discovery of the failure until the train was returned to service:

Not applicable - no failures that rendered a train of a safety system inoperable were involved.

H. Method of discovery of each component or system failure or procedural error:

The SGTR was discovered as described in Section I.B.

During the event, it was discovered that RU-141 was not reading correctly. A comparison of the monitor readings with the grab sample results obtained during the event indicated that the monitor was reading approximately 6 times less than the actual

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TEXT

gaseous activity. As a result, the initial offsite dose projections based on the release rate indicated by RU-141 underestimated calculated doses by a factor of 6. As soon as the discrepancy was discovered, subsequent offsite dose projections were corrected by increasing the monitor readings by a factor of 6 to compensate for the under-response. As a result of the discrepancy, an ERCFA for RU-141 was initiated.

During the investigation of this event, it was determined that the PVNGS DLT and FRP differ from the Combustion Engineering "Emergency Procedure Guidelines," (CEN-152). CEN-152 uses activity trends on the secondary side to aid in diagnosis of events. The PVNGS DLT differs in that alarm indications rather than activity trends are used. Additionally, there is a continuously applicable step in the Containment Integrity Safety Function section of CEN-152 to check for indications of secondary side activity, and if indicated, steps to depressurize and isolate the affected steam generator are performed. The PVNGS FRP only checks once for secondary side activity. These deviations are not justified in the Plant Specific Technical Guidelines. A SGTR may have been diagnosed earlier in this event if there had been a step in the DLT to trend secondary side activity or in the FRP to continuously check for indications of secondary side activity.

I. Cause of Event:

An investigation of this event was conducted in accordance with the PVNGS Incident Investigation Program. The manual reactor trip was initiated due to low pressurizer level and pressure. Approximately 22 seconds later, valid actuations of the Safety Injection Actuation System (SIAS) and the Containment Isolation Actuation System (CIAS) occurred due to low pressurizer pressure. The cause of the RU-141 failure is dicussed in Section I.D. The cause of the RCS leakage was a SGTR in Steam Generator 2.

A Steam Generator Tube Rupture Task Force was formed to perform an equipment root cause of failure analysis. The task force identified the most probable causal factors for degradation of the affected tubes. The evidence indicated that the rupture of the steam generator tube was due to IGA/IGSCC which occurred as a result of tube-to-tube crevice formation (SALP Cause Code C: External Cause). Several additional contributing factors such as increased sulfate levels due to resin intrusion, likelihood of cold working due to surface scratches, a less than standard microstructure in the ruptured tube, and increased susceptibility of contaminant concentration in the upper region of the tube bundle were also identified by the task force. The Steam Generator Tube Rupture Analysis Report was submitted by letter

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102-02569, dated July 18, 1993, from W. F. Conway to the NRC. Additional information related to the tube failure is dicussed in Sections I.D and I.E.

J. Safety System Response:

The following safety systems actuated as a result of the event:

- High Pressure Safety Injection System (BQ), Trains A and B
- Low Pressure Safety Injection System (BP), Trains A and B
- Containment Spray System (BE), Trains A and B,
- Emergency Diesel Generators (EK), Trains A and B,
- Essential Chilled Water System (KM), Trains A and B
- Essential Cooling Water System (BI), Trains A and B,
- Essential Spray Pond System (BS), Trains A and B
- Condensate Transfer System (KA), Trains A and B,
- Control Room Essential Heating, Ventilation, and Air Conditioning (HVAC) System (AHU)(VI), Trains A and B,
- Auxiliary Building Essential HVAC System (AHU)(VF), Trains A and B,
- Fuel Building Essential HVAC System (AHU)(VC), Trains A and B,
- Engineered Safety Features Switchgear Essential HVAC System (AHU)(VJ), Trains A and B,
- Containment Isolation System (JM), and
- Auxiliary Feedwater Pump (P) (BA), Train B

K. Failed Component Information:

The cause of the RCS leakage was a tube failure in Steam Generator 2. The steam generator is a Combustion Engineering System-80 vertical U-tube heat exchanger which operates with the reactor coolant on the tube side and secondary coolant on the shell side.

RU-141 had an undetected equipment failure that caused it to read approximately 6 times less than grab sample activity. The monitor would have reached the alert alarm level setpoint during the event at approximately 0456 MST, on March 14, 1993, if it had been indicating properly. The gas monitor is a Kaman Beta Scintillator, model number KMG-HRN 450809-002, with a range of 1.0 E-6 to 1.0 E-1 μCi/cc.

II. ASSESSMENT OF THE SAFETY CONSEQUENCES AND IMPLICATIONS OF THIS EVENT:

A safety limit evaluation was performed as part of the PVNGS Incident Investigation. The evaluation determined that the plant responded as

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designed, that no safety limits were exceeded, and that the event was bounded by current safety analyses.

Nuclear Fuel Management personnel performed a safety assessment of the event and determined that the equipment and systems assumed in the Updated Final Safety Analysis Report (UFSAR) Chapter 15 were functional and performed as required. Scenarios defined in UFSAR Chapter 6 concerning loss of coolant accidents were not challenged during this event.

The safety assessment concluded that the event did not result in a transient more severe than those previously analyzed. This determination was based on an evaluation of actual event parameters and dose assessments, compared to those contained in UFSAR, Section 15.6.3.1, Combustion Engineering Standard Safety Analysis Report, Section 15.6.3.2, and the SGTR with Loss of Offsite Power (SGTRLOP) reanalysis which was performed in accordance with Revision 1 to the "Steam Generator Tube Rupture Analysis Concerns and Justification for Continued Operation" (JCO 91-02-01). There were no adverse safety consequences or implications as a result of this event. This event did not adversely affect the safe operation of the plant or the health and safety of the public. The 2-hour exclusion area boundary thyroid dose was calculated to be less than 0.3 millirem and the 8-hour low population zone thyroid dose was calculated to be less than 0.04 millirem. These doses are much less than the Standard Review Plan 15.6.3 acceptance criteria of 30 Rem thyroid.

During the safety assessment of this event, concerns were raised regarding the differences in the timing of operator actions to isolate the ruptured steam generator as assumed in UFSAR Chapter 15 SGTR event, and the timing of those actions in the actual event. Similar concerns, however, were previously identified in October, 1991, as documented in JCO 91-02-01. In response to these concerns, the primary system equilibrium dose equivalent Iodine-131 (DEQI131) is currently limited to 0.6 μCi/gm in all three units, and a SGTRLOP reanalysis has been performed to verify that a more conservative treatment of operator timing, combined with the Technical Specification activity limits (1.0 and 0.1 μCi/gm for primary and secondary activity respectively), would not result in dose consequences greater than the acceptance criteria. The reanalysis is the most current analysis for a SGTR or SGTRLOP event. The results of the reanalysis are within the Standard Review Plan 15.6.3 acceptance criteria of 30 Rem thyroid.

The safety assessment of the event concluded that the longer interval required for isolation of the ruptured steam generator was compensated for by the low primary and secondary activities in effect at the time of the rupture. However, a supplemental evaluation was performed using a "best-estimate" transient evaluation code to evaluate the dose

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consequences associated with a steaming interval consistent with the actual event, with the affected generator steaming directly to the atmosphere and not through the condenser, and with DEQI131 activity levels at the Technical Specification limits. The resulting dose consequences for this supplemental case were also well within the acceptance criteria of 30 Rem thyroid and are bounded by the SGTRLOP reanalysis.

III. CORRECTIVE ACTION:

A. Immediate:

An investigation team was formed and an investigation was initiated in accordance with the PVNGS Incident Investigation Program. As part of the investigation, PVNGS initiated a root cause investigation.

B. Action to Prevent Recurrence:

As a result of the investigation, PVNGS has implemented changes to the Emergency Operating Procedures as corrective actions to address the CEN-152 DLT deviation described in Section II.H. These changes allow the CRS to consider past and present RMS alarms when performing the DLT and establishing procedure entry conditions. These changes will also allow the use of the Nitrogen-16 gamma response of the Main Steam Line Radiation Monitors (RU-140) and the use of the Steam Generator Blowdown Monitors (RU-4 and RU-5), both of which may clear by the time the CRS makes a diagnosis of the event. Changes have been made to the Emergency Operating Procedures to trend radiation monitors to aid in diagnosis of reactor trip events.

Additionally, PVNGS has implemented changes to the Emergency Operating Procedures as corrective actions to address the CEN-152 FRP deviation described in Section I.H. Changes have been made to the FRP to continuously apply the step to check for indications of a steam generator tube leak throughout the Event Control section of the FRP. Continuously applying this step in the Event Control section of the FRP serves the same function at PVNGS as continuously applying the step in the Containment Integrity Safety Function section of CEN-152. As an enhancement, changes were also made to expand the indications used for checking for indications of a steam generator tube leak.

A Steam Generator Tube Rupture Task Force was formed to perform an equipment root cause of failure analysis, evaluate the conditions which led to the tube failure, to develop the response and

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recovery efforts, and to ensure that necessary corrective actions were implemented. Corrective actions, primary-to-secondary leakage monitoring, and program enhancements were developed based upon the results of the task force findings and are being tracked to completion under the PVNGS Commitment Action Tracking System. The Steam Generator Tube Rupture Analysis Report contains a detailed description of the task force findings and was submitted by letter 102-02569, dated July 18, 1993, from W. F. Conway to the NRC.

The photo multiplier tube and the scintillation crystal were replaced in RU-141 and the monitor was successfully calibrated. The RU-141 monitor readings in Units 1 and 3 were as expected when compared to the grab sample results. As discussed in Section I.D, previous commitments have been made to the NRC to resolve the moisture problem affecting the operability of RU-141. A design change package for all three units was initiated prior to this event to reroute the condenser air removal system (CARS) condenser vacuum exhaust to the plant vent exhaust eliminating an effluent release path, to convert RU-141 to a CARS in-duct monitor, and to make appropriate hardware and software changes to RU-141. These changes include the removal of the heat tracing. The DCP for RU-141 is being installed to improve the reliability of monitoring the CARS exhaust for increases in radioactivity as a result of primary to secondary leakage via the steam generator.

IV. PREVIOUS SIMILAR EVENTS:

There have been no previous similar events reported pursuant to 10CFR50.73.

V. ADDITIONAL INFORMATION:

Radiological smears were taken to quantify any potential radioactive release which may have occurred through the auxiliary steam relief valve. The results of those surveys were negative.

HPSI flow indication in the Control Room does not indicate full scale such that Control Room personnel have no indication of HPSI flow less than approximately 75 gpm. The simulator does not simulate the square-root-extractor in the flow indicator circuitry and does indicate flow in the 0 to 10 percent range. Operator training was deficient in identifying this difference to Control Room personnel. The PVNGS Incident Investigation evaluated this condition for potential corrective actions. Based on the evaluation, the simulator has been upgraded to exhibit the square-root-extractor function on flow indicators.

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In order to determine if any indication of RU-141 failure was present prior to the event, the weekly grab samples obtained from the condenser exhaust during the previous month were reviewed. The activity of the grab samples taken on March 4, 1993, and March 5, 1993, were greater than 5.0 E-6 μCi/cc and significantly greater than the corresponding RU-141 readings. This is unusual in that the monitor reading is normally greater than the grab sample results. An investigation was initiated to determine why RU-141 was not declared inoperable based on the discrepancy between the grab sample and the monitor reading. The investigation determined that the appropriate data reviews of the sampling results had not been adequately performed and therefore an opportunity was missed to detect the monitor failure. The individuals involved have been disciplined under the APS Positive Discipline Program.

VI. SPECIAL REPORT:

In Palo Verde Unit 2, there have been 7 total accumulated actuation cycles of the Emergency Core Cooling System to date. This satisfies the requirements of Technical Specification 3.5.2 ACTION b.

AIT No. 213/93-80
Haddem Neck

U. S. NUCLEAR REGULATORY COMMISSION
REGION I
AUGMENTED INSPECTION TEAM REPORT

INSPECTION OF TWO LOSS OF OFFSITE POWER EVENTS
AND A LOSS OF MOTOR-CONTROL-CENTER-5

REPORT NO.	93-80
DOCKET NO.	50-213
LICENSE NO.	DPR-61
LICENSEE:	Connecticut Yankee Atomic Power Company P.O. Box 270 Hartford, Connecticut 06141 - 270
FACILITY:	Haddam Neck
INSPECTION DATES:	June 30 - July, 9, 1993
INSPECTORS:	F. Burrows, Electrical Engineer, NRR B. Raymond, Sr. Resident Inspector - Haddam Neck T. Shedlosky, Project Engineer, RI

TEAM LEADER: Jm Trapp 8-10-93
James M. Trapp, Team Leader, Engineering Branch, DRS
Date

APPROVED BY: Jacque P. Durr 8/11/93
Jacque P. Durr, Chief, Engineering Branch, Division of Reactor Safety
Date

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EXECUTIVE SUMMARY

The scope of the Augmented Inspection Team (AIT) inspection was provided by the Region I Regional Administrator in the Augmented Inspection Team Charter. The team was tasked with conducting a detailed review of the circumstances surrounding the June 22, 1993 and June 26, 1993, losses of offsite power and the June 27, 1993, loss of motor-control-center-5. Specifically, the team was tasked with developing a detailed sequence of events, evaluating the root cause determination, assessing the effectiveness of the corrective actions, and evaluating the safety significance for each event.

On June 22, 1993, while performing breaker failure trip logic testing on the offsite power tie breaker, the station experienced a total loss of offsite power. In response to the loss of offsite power, both emergency diesel generators automatically started and provided emergency power to the station. The plant was in cold shutdown at the time of the event and shutdown cooling was temporarily lost. This event was important to safety because of the temporary loss of shutdown cooling and the loss of offsite power is a precursor to a station blackout. The root cause for this event has been identified as a wiring error in offsite power tie breaker 12R-1T-2 breaker failure trip logic. The wiring error occurred during or shortly following plant construction. The wiring error had not been previously identified since this was the first test conducted of this particular trip logic which included tripping the breakers. An evaluation of the wiring error's effect on plant safety concluded that the error did not degrade plant safety margins and could be left as-is. The basis for this conclusion was that the station emergency power supplies could be isolated from offsite power system faults by safety-related breakers and the reliability of the offsite power supply was not degraded. The team concluded that the root cause had been correctly identified and the corrective actions were acceptable. Operator performance in response to the loss of offsite power was determined to be good.

On June 26, 1993, while performing surveillance testing of train A of the safety injection actuation logic with a partial loss of offsite power, a complete loss of offsite power occurred. In response to the loss of offsite power, the emergency diesel generators automatically started and shutdown cooling was restored. The root cause of this failure was determined to be a blown fuse to a bus voltage sensing relay. The fuse was likely blown during maintenance being performed on associated equipment. The fuse was replaced and the surveillance procedure was revised to verify that the bus voltage sensing relay fuses were not blown prior to conducting this test. The team determined that the operator response to the loss of offsite power was good. The root cause for this event was a blown fuse and the corrective actions taken were appropriate. The team concluded that the June 22 and June 26 events were not related in that the corrective actions from the first event could not have precluded the second event from occurring.

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On June 27, 1993, while performing surveillance testing of train B of the safety injection actuation logic with a partial loss of offsite power, a temporary loss of motor-control-center-5 (MCC-5) occurred when the automatic bus transfer scheme failed to operate. Power was quickly restored to the motor-control-center by manually closing a breaker to an energized bus. Following this event, an erroneous event classification of an alert was sent to the state and local authorities. The event classification was corrected to an unusual event a short time later. This event was important to safety because MCC-5 provides power for the emergency core cooling system injection valves and the successful operation of MCC-5 is essential for the emergency core cooling systems to function. The root cause evaluation of this event failed to positively identify a root cause for the failure. The evaluation was successful in identifying two components which had the highest probability of having caused the failure. Both of these components have been replaced and the automatic bus transfer (ABT) has been successfully tested numerous times since the event. Because the exact cause of the failure has not been positively identified, a number of compensatory actions were proposed by the licensee. These actions include additional system and component testing, online inspections of suspected components, a design review of the ABT scheme, and resolving a potential generic issue with 52X relay coil plunger sticking. The team reviewed these compensatory measures and determined they were appropriate. The misclassification of the event as an alert was determined to be a performance error by a non-licensed shift member who transmitted the message. The team concluded that the root cause evaluation and testing were thorough and the corrective actions taken in response to this event were appropriate.

The team also noted two issues regarding the licensing basis of MCC-5. The updated UFSAR, Section 8.3, states in part that "The Class 1E system has the redundancy, capacity, capability, and reliability to supply power to all safety-related loads. This system ensures a safe plant shutdown to mitigate accident effects, even in the event of a single failure." This statement does not appear to be accurate as related to single failures and MCC-5. In addition, the team questioned the applicability of 10CFR 50.46 (d), which explicitly states that the performance of the emergency core cooling system (ECCS) system must include in particular Criterion 35 of Appendix A, which requires that the ECCS safety function be accomplished assuming a single failure. The current design of the ECCS system does not satisfy the requirement of Criterion 35 due to the single failure vulnerabilities of MCC-5. While the team noted that an exemption had been granted by the NRC for the MCC-5 single failure vulnerability during original plant licensing, an explicit exemption from the 50.46 requirement was not apparent to the team. Both of these issues are currently being reviewed by the NRC.

DETAILS

1.0 INSPECTION OBJECTIVE

The scope of the Augmented Inspection Team (AIT) inspection was provided by the Region I Regional Administrator in the Augmented Inspection Team Charter (Attachment C). Generally, the team was tasked with conducting a detailed review of the circumstances surrounding the June 22, 1993 and June 26, 1993 losses of offsite power and the June 27, 1993 loss of motor-control-center-5. Specifically, the team was tasked with:

- Developing a detailed sequence of events.
- Collecting, analyzing and documenting factual information to determine the causes, conditions, and circumstances pertaining to each event.
- Evaluating the licensee response to each event including the corrective actions and the inappropriate Emergency Action Level declared following the June 27, 1993 event.
- Assessing the safety significance of each event and communicating to regional and headquarters management the facts and safety concerns related to problems identified, including single failure vulnerabilities and impact of non-safety related equipment on safety-related equipment.
- Evaluating the knowledge and performance of the licensee staff during these events.
- Evaluating the maintenance testing and any changes made to the design which may have contributed to this failure.

This inspection report is divided into three sections with each section providing a description of each event and the team's findings. It was not the responsibility of the AIT to recommend enforcement actions. These aspects will be addressed in subsequent NRC correspondence.

2.0 DETAILED INSPECTION FINDINGS

2.1 LOSS OF OFFSITE POWER EVENT (June 22, 1993)

2.1.1 Description of Event

An unplanned loss of offsite electrical power was caused during a test of transmission line protective equipment on June 22, 1993, at 09:15. The plant was in Operational Mode 5 (cold shutdown) at the time of the event with the reactor coolant system level in the pressurizer and the 'A' residual heat removal (RHR) pump in service for core decay heat removal.

Following the loss of offsite power, both emergency diesels started and energized the safeguards electrical buses. All safety-related equipment functioned properly. Control room operators followed the instructions provided in Emergency Operating Procedure (EOP) 3.1-10, "Partial Loss of AC." They restored core cooling RHR flow in two minutes, service water cooling to the component cooling water (CCW) heat exchangers in eleven minutes and spent fuel pool cooling in twenty-five minutes. Offsite power was restored to station service Bus 1-2 at 09:28. Power was available from both 115 Kilovolt (kV) transmission lines into the switchyard during this event.

The loss of offsite power was classified as an Emergency Action Level Unusual Event at 09:36. The NRC Duty Officer was notified at 09:41 and the event classification was promulgated outside the station using the Emergency Notification and Response System (ENRS) at 09:46. The Unusual Event was terminated at 11:15.

Background

Offsite power is supplied to the station by two 115 kV transmission lines. This offsite power system delivers all station service power while the plant is shutdown or operating at low power. Above approximately ten percent power, the unit auxiliary transformer, which is supplied from the main generator output, delivers power to the reactor coolant pump motor buses only. The 115 kV system supplies all other station service and safeguards electrical buses. The 115 kV system is unaffected by a turbine generator trip as the main generator supplies power to a separate 345 kV distribution system.

The 115 kV system normally receives electric power from two separate offsite sources (Figure 1). Transmission lines from Middletown (1772) and Haddam (1206) supply power to the station 4160 Volt buses through two 115 kV to 4.16 kV station service transformers T-389 and T-399. The two transformers supply power to station service Buses 1-2 and 1-3 through circuit breakers 3891 and 3991, respectively. A normally closed oil circuit breaker 389T399 (12R-1T-2) connects the two 115 kV transmission lines. A normally open circuit breaker B-2T3 can be closed to tie the two 4160 Volt station service buses together in the event that power from either 115/4.16 kV station service transformer is not available. The transformers, the oil circuit breaker 12R-1T-2 and associated motor operated disconnects are all located within the 115 kV switchyard. The 4160 Volt circuit breakers 3891, 3991 and B-2T3 are installed in Buses 1-2 and 1-3 located in the plant "A" switchgear room.

The two 4160 Volt station service buses normally supply the two safeguards electrical buses, Bus 8 and Bus 9. Each of these may be powered from the emergency diesel generators and are each separated from the station service buses in the event of an undervoltage condition by two circuit breakers in series.

There is overlapping responsibility between the plant and other utility organizations for the design, operation and maintenance of the offsite power supply. The Connecticut Valley Electric Power Exchange (CONVEX) load dispatcher has jurisdiction for the operation of the 115 kV lines and associated switching equipment up to and including the 4160 Volt supply breakers 3891 and 3991 to Buses 1-2 and 1-3. Although, those circuit breakers are operated from the plant control room; their position is coordinated with the CONVEX. The plant control room operators also keep CONVEX informed of the position of the normally open 4160 volt bus tie breaker B-2T3. The 115 kV tie breaker 12R-1T-2 may be controlled remotely by the dispatcher; however, it is normally kept in local control from the plant control room. The control room operators are not restricted in operating this equipment in the event of an emergency. The station has maintenance responsibility for all equipment starting with the 115 kV motor operated disconnect at the primary side of each 115/4.16 kV transformer. The Connecticut Light and Power Company, Regional Test Department is responsible for transmission line protection including its design control and testing.

The June 22, 1993, loss of offsite power involved a test of the protective devices that act in the event breaker 12R-1T-2 fails to open when a fault is detected on one of the lines. Both transmission lines are protected by several types of fault detection devices arranged into primary and backup groups. In addition to tripping open the transmission line breakers at remote sub-stations, both the primary and backup devices will trip breaker 12R-1T-2. That breaker has redundant trip coils fed separately by each relay group.

Breaker 12R-1T-2 is monitored for proper operation by a breaker failure scheme. In the event that breaker 12R-1T-2 fails to open, this protection circuit acts to open remote substation breakers supplying power to both the Haddam (1206) and Middletown lines (1772) in order to de-energize the faulted line from the other sources of power. In addition to opening the remote 115 kV breakers, the breaker failure protection logic also trips open the 4160 Volt supply breakers 3891 and 3991. These breakers are tripped to isolate any potential electrical sources, such as the emergency diesel generators, from feeding the faulted transmission lines. Unless isolated for testing, actuation of the 12R-1T-2 breaker failure logic will always cause a full loss of offsite power at the Haddam Neck Plant.

Connecticut Light and Power Company, Regional Test Department is responsible for transmission line protection including design control. Its personnel conduct the tests of transmission line protective devices including the 12R-1T-2 breaker failure logic. Their activities are coordinated by plant personnel who developed procedures and interface with plant operations. Prior to this refueling outage, the maintenance department had been responsible for coordinating this testing. This responsibility was transferred to the Generation Test Department because their skills and work activities are more closely related to control logic and electrical protective device testing. The test procedures used were revised to enhance the scope of testing. Preventative Maintenance Procedure PMP 9.8-117, "1206 Connecticut Yankee - Haddam Line Trip Test," replaced the previous test procedure and became effective on April 30, 1993. Changes to the procedure included verifying a trip signal from a transmission line protective device to each of the station service bus supply breakers. During the test Bus 1-3 supply breaker 3991 was to be racked into the test position and tripped open. Previously, the breaker failure trip signal had been interrupted at a test switch that prevented a trip of the on-site 4160 Volt breakers or a trip of the remote substation 115 kV breakers.

Event Time Line

The tests of the Haddam transmission line protective devices were first performed with the recently revised procedure PMP 9.8-117 on June 22, 1993. This test was to include an actual trip of the Bus 1-3 supply breaker 3991, which was withdrawn from the switchgear to the test position. To support the test, station service power was supplied from offsite through the other 4160 Volt breaker, 3891, to Bus 1-2. The normally open bus tie, B-2T3, was closed to supply Bus 1-3 from Bus 1-2.

Section 6.2 of the test procedure verified the ability of the 12R-1T-2 breaker failure logic to trip the 3991 breaker. The test procedure initial conditions, procedure step 6.1.5, isolated all output trip functions from the logic. Then switch contacts 8 and 8c were closed to enable the 3991 breaker trip. At 09:15 the test technicians initiated the breaker failure logic by manually actuating a station service transformer T-399 differential current protective device (procedure step 6.2.3). Upon initiating a breaker failure signal, the 3891 breaker tripped open instead of the 3991 breaker. This resulted in a loss of offsite power because all power to the station was supplied through breaker 3891. Both emergency diesel generators started and energized safeguards electrical Buses 8 and 9. The shutdown cooling flow was restored in two minutes and spent fuel pool cooling was restored in twenty-five minutes. There was no noticeable increase in reactor coolant or spent pool temperatures. A planned radioactive liquid release was in progress and terminated with the loss of power. The sequence of events for the June 26 loss of offsite power are provided below:

07:44	Close Bus 1-2 to 1-3 tie breaker B-2T3, breaker 3991 in test position
09:15	Commenced breaker failure test, breaker 3891 tripped open, loss of all incoming power, offsite 115 kV lines remain energized, both emergency diesel generators start and energize Buses 8 and 9
09:17	Control room operators start A-RHR pump and C-CCW Pump
09:18	Control room operators start B-CCW pump
09:26	Service water cooling restored to both CCW heat exchangers
09:28	Control room operators shut breaker 3891, energized Bus 1-2
09:40	Restored spent fuel pool cooling
09:46	Promulgated declaration of Unusual Event
09:50	Completed actions under EOP 3.1-10
11:02	Shut breaker 3991, opened breaker B-2T3
11:12	Terminated Unusual Event

2.1.2 Corrective Actions

Root Cause

Licensee personnel examined the point-to-point wiring associated with contacts 8 and 8c of the 12R-1T-2 breaker failure lock-out relay, 86BF-A, and its associated test switch and identified that these contacts were inadvertently wired to the station service breaker 3891 trip circuit. Although this wiring should have been in the trip circuit for station service breaker 3991, it was functionally wired in parallel with the breaker 3891 trip circuit that is associated with contacts 9 and 9c of the lock-out relay. There was no other connection from the breaker failure logic to station service breaker 3991 trip circuit.

The licensee suspects that this wiring error had been made early in plant life, possibly before commercial operation. This is because of the type of wire, lack of circuit number labels, type of crimp lug, and the type of crimp tool used were different than those used for the other trip circuits. The wires were not included in laced bundles, but appear to have been installed following construction of the control boards. Specifically, the main control board wiring drawings specified that the two wires from terminal 8c of device "ON" and terminal 16 of device "OP" were to be connected to terminal 2 and 3, respectively, of device "PB" that is part of the breaker 3991 trip circuit (control circuit bus numbers 523P and 523T). Instead, the wires were taken to terminals 5 and 7 of device "AJ," which is in the breaker 3891 trip circuit (control circuit bus numbers 522P and 522T).

The licensee intends to correct the wiring error during the next refueling outage following a review of the 12R-1T-2 breaker failure circuit. Additionally, the licensee intends to test the revised circuit. However, because the breaker failure circuit is common to both sources of offsite power, there is a risk of causing additional losses of offsite power events while performing the post modification retest. For this reason, the licensee intends to evaluate and determine the optimum test configuration to minimize risk during testing. The circuit drawings were revised to reflect the as built configuration of the 12R-1T-2 breaker failure circuit and the breaker 3891 and 3991 trip circuits.

Justification for Operation

A technical evaluation was prepared to justify operation during the next cycle with the existing wiring configuration. This justification was based on the qualification of the Category 1E loss-of-Voltage relays to protect the on-site electrical distribution system from conditions occurring on the offsite supply system. These Category 1E protective devices operate to protect the emergency diesel generator from the offsite system. In the case of a loss of offsite power while the emergency diesel generator is operating in parallel with the system, voltage will decay rapidly, due to the high impedance of the generator. The bus

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undervoltage relays will trip the safeguards bus free of offsite power within two seconds. Also, the generator impedance will limit fault currents to low levels. This provides a self limiting characteristic that protects the generator from external faults.

The Connecticut Light and Power Company, Transmission and Distribution Department has design jurisdiction over the 12R-1T-2 breaker failure logic. Representatives of that organization concurred in the plant operating for an additional cycle with the wiring configuration as-is. This was based on the low probability for back-feed from the plant electrical system into the 115 kV distribution system. The effect of the "2B"-emergency diesel generator monthly surveillance test concurrent with operation of the breaker failure circuit was acceptable due to the size of the generator, the plant and transmission system impedance and the ability of Class 1E protection devices to isolate the generator.

2.1.3 Conclusions

Event

The loss of offsite power was important to safety because shutdown cooling was temporarily lost and the loss of offsite power is a precursor to a station blackout. The actual event had minor significance due to the low decay heat generation rate and the condition of the emergency diesel generators that were both operable during the event. It occurred 39 days after the reactor had been shutdown for the refueling outage. Operator performance was good in restoring reactor core decay heat removal and spent fuel pool cooling in a short period of time. All safety-related equipment functioned as expected. The classification of this event by plant operators as an Unusual Event was appropriate.

This event was caused by a wiring error that probably occurred early in plant life. The team independently verified the root cause by observing the wiring error. The deficiency in wiring the breaker trip circuit had been identified as result of a recent initiative to improve upon the scope of transmission line periodic tests. The newly revised test procedure used to conduct this test provided adequate detail and did not contribute to the cause of this event. The test was successful in identifying long standing deficiencies in the plant configuration.

Corrective Action

The team concluded that the technical justification for not correcting the wiring error to the breaker trip circuit prior to the next refueling outage was acceptable. The purpose for tripping the station service supply breakers 3891 and 3991 is to provide isolation of a fault and therefore prevent back-feeding the fault from the station. Each safeguards electrical bus is isolated from the non-safety station service bus by two breakers in series and a qualified bus undervoltage protection circuit. The emergency diesel generator winding impedance will act to limit fault current. The limited fault current and the settings of the undervoltage protection act together to avoid sustaining damage to the generator. In addition, the 12R-1T-2 breaker failure trip is a backup to the primary and secondary breaker trip schemes

r. :renced in the final safety analysis report (FSAR) and is to protect non-safety-related transmission equipment. If a breaker failure were to occur, the logic would trip open the Middletown and Haddam transmission line breakers at their respective switchyards. Therefore, leaving the wiring error as-is has no effect on the reliability of offsite power sources.

The team concluded that the licensee's action to revise drawings to reflect the plant as-built conditions is appropriate when taken with their plans to verify, correct and test the 12R-1T-2 breaker failure protection logic during the next refueling outage.

2.2 LOSS OF OFFSITE POWER EVENT (June 26, 1993)

2.2.1 Description of Event

The plant was in Operational Mode 5 (cold shutdown) on June 26 with the reactor coolant system level in the pressurizer and the `B' residual heat removal (RHR) pump in service for core decay heat removal. Licensee personnel completed preparations to perform a partial loss of normal power test in accordance with procedure SUR 5-1-18, "Test of Train A SIAS with Partial Loss of AC." The test is conducted each refueling outage. The objective of the test was to verify the proper operation of the Train A safety systems in response to a simulated safety injection actuation signal coincident with a loss of normal power. The test verifies that safety equipment is capable of starting and being powered from the `A' emergency diesel generator. The initial station electrical lineup was established in the normal configuration that separates the two trains, allowing test personnel to de-energize the Train A side (Bus 1-2), while the Train B side (Bus 1-3) equipment remains powered by the offsite power source during the test (Figure 1).

Plant personnel aligned the Train A safety systems in a standby condition. In accordance with SUR 5.1-18, breaker 3891 was closed to supply power to Bus 1-2 and breaker 3991 was closed to supply power to Bus 1-3. The cross-tie breaker B-2T3 was open. At procedure step 6.2.5, plant personnel initiated a partial loss of power by opening the Bus 1-2 supply breaker, 3891, and simulated a low pressurizer pressure condition to initiate a Train A safety injection actuation signal (SIAS). When step 6.2.5 was performed, the Train A side de-energized as expected, but supply breaker 3991 to Bus 1-3 also opened which de-energized the Train B side. The plant experienced a complete loss of normal power (LNP) from the offsite distribution system at 19:17.

Event Time Line - Operator Response

Plant operators immediately identified the unexpected operation of breaker 3991, secured from testing, and entered Emergency Operating Procedure (EOP) 3.1-10, "Partial Loss of AC." Both emergency diesel generators automatically started and energized the emergency buses as expected. Plant operators restored shutdown cooling and component cooling. The operators manually started the `B´ RHR pump within 3 minutes of the LNP; however, the pump tripped after running less than a minute. The `A´ RHR pump was started and it ran satisfactorily. The reactor heat-up was less than 2 degrees fahrenheit (°F) during the time that shutdown cooling system was not operating.

The operators restored offsite power at 19:34 by closing breaker 3891 to power Bus 1-2, and then closing tie breaker B-2T3 to power Bus 1-3. Breaker 3991 was left open pending the completion of a review to determine the cause of its unintended operation. Emergency Buses 8 and 9 were transferred to the offsite supply at 19:40. The spent fuel pool cooling pumps were restarted within 44 minutes of the LNP. The spent fuel pool temperature increase was less than 5°F.

While completing actions to secure from the test, the operators classified the loss of offsite power as an Unusual Event emergency, and reported the event to the offsite state and local authorities at 19:36. The Unusual Event classification was reported to the NRC Duty Officer at 19:48, as required by 10 CFR 50.72. The operators exited EOP 3.1-10 at 20:01 after returning the spent fuel cooling system to normal. The sequence of events for the June 26 LNP are provided below.

19:17	Initiate simulated Train A SIAS and Partial LNP.
19:17	Breaker 3891 manually opened and 3991 unexpectedly opened - Result total LNP.
	Emergency Diesels start and Power Emergency Buses
19:20	`B´ RHR pump manually restarted.
19:21	`B´ RHR pump tripped; `A´ RHR pump started.
19:34	Breakers 3891 & B-2T3 closed to power Buses 1-2 & 1-3.
19:35	Unusual Event Notification sent.
19:40	Emergency Buses 8 & 9 transferred to offsite supply.
19:48	NRC Duty Officer notified of Unusual Event.
20:01	`B´ spent fuel pool cooling pump started.
20:01	Operators exit EOP 3.1 - 10.
20:42	NRC Duty Officer Notified of Unusual Event - Terminated.

Aside from the trip of the `B´ RHR pump, all other equipment operated as expected. While restoring the system lineups following the LNP, the operator attempted to close high pressure safety injection valves 861A and 861B, which opened in response to the SIAS. This was done prior to resetting the safety injection lock-in relays. The valves automatically re-opened as designed. The operator realized his error, reset the safety injection lock-in relays. The operator then noticed that the breakers for the valves were open with the valves in the mid-position. The breakers were reset and the valves were closed without further problem.

Undervoltage Trip Scheme - Design & Operation

The loss of normal power event occurred as a result of an inadvertent operation of the undervoltage trip and lockout scheme on 4160 Volt Bus 1-3. The 4 kilovolt (kV) bus undervoltage trip scheme is shown on the simplified one line diagram in Figure 2, and in the logic diagram in Figure 3. The high side of potential transformers (PT) are connected to each phase of Buses 1-2 and 1-3 in a wye configuration. The low side of each PT is also connected in a wye configuration with the center phase connected to ground. The low side of the PT branches to several relay and instrumentation circuits.

One circuit from phase 3 (line 3V29) is protected with a 6 amp fuse and feeds a voltmeter, a test transformer, and undervoltage relay 27B. Relay 27B is connected across phases 1 and 3 and is used in the trip and lockout protection scheme for Bus 1-3. The test transformer is used to provide low voltage supply internal to the protection cabinets to power the pilot wire trip signals. The voltmeter is located on the main control board and displays Bus 1-3 voltage. The operator can switch the voltmeter to read across the different Bus 1-3 phases by manipulating a switch on the main control board. The selector switch consists of a multi-stacked series of contact wafers and also controls the readouts on voltmeters for Buses 1-2, 1-1A and 1-1B.

The trip and lockout scheme uses undervoltage relays (27A & 27B) on both 4160 Volt buses and works on a logic that requires that an undervoltage condition be sensed on both Buses 1-2 and 1-3 before a trip signal is generated to lockout the power supplies to the bus (See Figure 3). The 6 amp fuse protecting line 3V29 had blown, leaving the 27B relay in a de-energized condition at the start of the test on June 26. This condition was not annunciated or otherwise indicated in the control room, and was not known to plant personnel during the conduct of the test. The fuse had blown some time prior to June 26, but the undervoltage logic had not actuated to lockout Bus 1-3 as long as power was available on Bus 1-2. When the operators opened breaker 3891 to conduct the Train A LNP test, the trip and lockout logic for Bus 1-3 was completed when the 27B relay on Bus 1-2 de-energized, and the total loss of offsite power occurred.

The licensee could not identify exactly when the fuse had blown, but concluded that the failure most likely occurred earlier in the outage. The PT circuit was disturbed when the voltmeter associated with line 3V29 was relocated as part of a control board design change.

Investigation of Anomalous Voltmeter Indications

In the evaluation of this event, the licensee identified a missed opportunity to have identified the failed fuse in the PT circuit. This opportunity occurred on about June 15 when plant operators noted an anomalous indication of the voltmeter following the restoration of a station service transformer T-399 to service after its replacement. Plant operators noted that the voltage reading on Bus 1-3 was about 200 Volts lower than that on Bus 1-2. The voltage reading should have been the same since both were powered from the 115 kV system.

The anomalous indication was discussed with Generation Test Services (GTS) personnel, who were responsible for the transformer work, the control board design changes, and for work related to the bus instrumentation and controls. The operator investigated the anomaly with a GTS technician. The investigation included the manipulation of the voltmeter selector switch to review the bus voltage indication on all three phases. The technician read nominal voltage on phase 1, about 95% of nominal on phase 2, and several hundred volts on phase 3 while troubleshooting the problem with the operator. The GTS technician erroneously diagnosed this indication as a likely problem with the selector switch, and not a blown fuse. The GTS technician stated that he needed to investigate the switch problem and correct it before plant restart, but he had prioritized follow-up of the problem for later in the outage. The drawings (Series 16103-32001, Sheets 5TA, 5TB, 5TC) were recently issued prior to this event as part of a program to upgrade plant records.

The AIT reviewed the PT circuit and concluded that the presence of the low impedance transformer in the circuit created voltage readings across the phases that tended to mask the blown fuse. The team concluded that the voltage readings were not obviously indicative of a blown fuse. The team noted further that neither the technician nor the operator submitted a trouble report for the anomalous voltage readings on June 15 in accordance with ACP 1.2-5.1, "PMMS Trouble Reporting System and Automated Work Order." This action would have entered the problem into the work control system to identify the defective equipment. However, the same technician who diagnosed the anomalous voltage indications with the operator on June 15 would also have been assigned to perform the follow-up repairs. The team concluded that had the equipment deficiency been incorporated in the work control program, it most likely would not have been identified as requiring repair prior to the conduct of SUR 5.1-18 and would not have prevented the June 26 LNP event from occurring.

Operator Use of the 4160 Volt Voltmeter

The team reviewed the circumstances involving an alleged reluctance by operators to use the selector switch for the voltmeter on the 4 kV buses due to an incident when the reactor tripped while manipulating the switch. The team confirmed that there was an event about 20 years ago during which the reactor tripped from the 4 kV bus undervoltage protection scheme. The licensee concluded at that time that the trip occurred due to the use of test equipment in use to monitor the protection scheme. The exact reason for the trip was not conclusively resolved, but there was no problem with the voltmeter selector switch either suspected or left uncorrected. Some operations and maintenance personnel were nonetheless left with the impression that there might be a problem with the selector switch. The operating practice of routinely using the switch to monitor 4 kV bus voltage on all three phases was changed to only monitor a single phase. That practice persisted until July 1993 and the selector switch was not routinely used.

The team determined from interviews with licensee personnel that some operators and maintenance personnel had the impression that "there might be a problem with the voltmeter selector switch," but others were not aware of the issue. The team noted that operators would use the switch if necessary and as required to review the status of the electrical system. The licensee changed the operating practice during this inspection to require the operator manipulate the switch every day to record 4 kV phase voltages as part of the daily control board rounds and log keeping.

It is notable nonetheless that the general impression that "there might be a problem with the selector switch" did have a bearing on the decision by the Generation Test technician to not investigate further the low voltage reading noted by the operators on Bus 1-3 on June 14.

2.2.2 Corrective Action

The license replaced the blown fuse in the PT circuit on June 27 after identifying the cause for the June 26 loss of offsite power. The Train A LNP test was successfully re-performed on June 27. Surveillance procedure SUR 5.1-18 (and 5.1-19 for the Train B) were changed by Temporary Procedure Change 93-5-4 on June 27 to add prerequisite step that required the operator to verify that the fuses are good prior to performing the surveillance test. The licensee also changed the control room operators round sheet to require that the voltmeter selector switch be exercised during daily reading on the 4160 Volt buses.

2.2.3 Conclusions

Event

The loss of offsite power was important to safety because shutdown cooling was temporarily lost and the loss of offsite power is a precursor to station blackout. However, during this specific event the safety significance was low since both emergency diesel generators were operable and offsite power remained available. The event occurred 43 days after the reactor had been shutdown for the refueling outage, and thus decay heat levels were relatively low. The team concluded that the June 22 and the June 26 events were not related in that the corrective actions from the first event could not have precluded the second from occurring.

Operator performance was good in restoring shutdown cooling and spent fuel pool cooling in a short period of time. Except for the RHR pump and the high pressure safety injection valve breakers, plant equipment functioned as expected during the event. The breakers for valves SI-861A & B are a Westinghouse motor circuit protection breaker, Type HMCP, that has been the subject of a generic concern for setpoint. The HMCP's tripped after the safety injection signal reversed the motor direction after the operator shut the valves. The licensee addressed the HMCP issue for these and similar breakers in a design change prior to restart from the outage. Further NRC follow-up of this issue is described in NRC Inspection Report 50-213/93-12.

The root cause for this failure was positively identified as a blown fuse in Bus 1-3 trip and lockout logic scheme. The PT circuit fuse most likely failed during the modification activity which relocated the associated voltmeter as part of the changes resulting from the detailed control room design review. The team reviewed the licensee statement that plant operators were reluctant to use the voltmeter selector switch and concluded that it was not relevant to this event.

The team noted that more detailed troubleshooting of the anomalous voltmeter indications on June 15 could have identified the failed fuse. However, the symptoms presented to repair personnel on June 15 were reasonably diagnosed as a likely problem with a switch contact, which warranted a lower priority for further follow-up.

Corrective Actions

The surveillance activity was successful in detecting a problem in the Bus 1-3 undervoltage protection circuit. The team concluded that it is not reasonable to expect that the plant surveillance procedure would check for blown fuses prior to the conduct of a partial LNP test. The procedure revisions and the replacement of the blown fuse were acceptable corrective actions. The licensee requirement to operate the voltage selector switch on a daily basis will assist in identifying fuse failures and avoid unnecessary plant transients.

2.3 LOSS OF MOTOR-CONTROL-CENTER-5 (June 27, 1993)

2.3.1 Description of Event

Background

Motor-control-center-5 (MCC-5) and its associated automatic bus transfer scheme (ABT) are a design which is unique to the Haddam Neck Plant. The design is necessary because both trains of certain valves are required to mitigate the consequences of certain accidents assuming a single active failure. For example, MCC-5 supplies electrical power to the high and low pressure safety injection system injection valves. These valves are normally closed and must open for the high and low pressure injection systems to operate. For the low pressure safety injection (LPSI) system to satisfy it's design basis flow, assuming a single failure of one LPSI pump, both injection valves must open. Similar constraints exist with the high pressure safety injection system. To address this design constraint, MCC-5 was designed with an automatic bus transfer (ABT) scheme which switches the 480 Volt electrical source for MCC-5 from its preferred supply bus (manually selected) to the alternate bus in the redundant train upon loss of power to the preferred source (see Figure 4). The transfer circuitry will also automatically transfer (MCC-5) back to the preferred bus if its voltage is subsequently restored. The automatic transfer circuitry contains appropriate interlocks to ensure that breakers 9C and 11C cannot be closed at the same time which would parallel the two emergency power sources. During original plant licensing, the NRC granted the licensee an exemption from assuming single failure of MCC-5. This exemption was required since a postulated single failure of the ABT would render both the high and low pressure emergency core cooling systems inoperable.

The MCC-5 ABT scheme is shown in Figure 4. The components making up the circuitry are two Westinghouse DB-25 480 Volt air circuit breakers with their associated integral components (identified with a 52 or 33 prefix), three Agastat timing relays (identified with a 62 prefix), a two-position preferred source selector switch, and several manual trip/close pushbuttons. The Agastat timing relays are used to detect voltage on Buses 5 and 6 and thus are the components that initiate the automatic transfer. The breaker control relays (52X) provide contacts to momentarily energize their corresponding breaker's closing coil and provide the anti-pump protection which prevents repeated breaker closure attempts. A functional description of the operation of the ABT transfer is provided in Attachment B and Figure 5 of this inspection report.

Time Line of Event

On June 27, 1993, the plant was in Mode 5 (cold shutdown) with the reactor coolant system level in the pressurizer and the shutdown cooling system in service for the train not being tested. The plant's procedures for conducting the partial loss of offsite power coincident with a safety injection actuation signal (SIAS) had been revised to include an integral test of the ABT of MCC-5 based on recommendations resulting from a probability risk assessment (PRA) study. Prior to this test, the MCC-5 automatic transfer function had not been formally tested.

Surveillance test procedure 5.1-18, "Test of Train A SIAS with a Partial Loss of AC," was successfully performed for the Train A. MCC-5 had transferred from Bus 5 to Bus 6 and back to Bus 5 when Bus 5 was energized by the emergency diesel generator. Following the successful completion of the Train A test, the licensee initiated testing the Train B using surveillance procedure 5.1-19, "Test of Train B SIAS with a Partial Loss of AC." An initial condition of this test is to select Bus 6 as the preferred source of power for MCC-5. Selecting Bus 6 as the preferred power source allows the ABT to transfer from Bus 6 to Bus 5 (energized by offsite power) when offsite power is secured on Bus 6. The ABT will transfer back to Bus 6, since it is the preferred source of power, when emergency diesel generator 2BB re-energizes Bus 6. At 18:48, breaker 3991 was opened to secure offsite power from Train B. Bus 6 (the preferred source), which was powering MCC-5, was de-energized and the automatic transfer to Bus 5 (alternate source of power for MCC-5) occurred as expected. Approximately 6 seconds later, after the Train B emergency diesel generator came up to speed, Bus 6 was re-energized. Because Bus 6 was selected as the preferred source, the breaker (9C) from Bus 5 powering MCC-5 tripped open, but the breaker (11C) from Bus 6 did not close as expected. As a result, MCC-5 was without power. In an attempt to restore power to MCC-5, an operator located at the ABT in the switch-gear room selected Bus 5 (position 1) as the preferred source of power for MCC-5. MCC-5 remained de-energized. The operator then attempted unsuccessfully to close breaker 9C by pressing the manual close pushbutton on the breaker. Subsequently, the operator was able to mechanically close Breaker 9C using a portable operating handle which re-energized MCC-5 from Bus 5 at 18:52. MCC-5 had remained de-energized for approximately 4 minutes during this event. The surveillance test was terminated and offsite power was restored to Train B.

Trouble-Shooting Activities

Several repeated operations of the ABT, following the event, between Buses 5 and 6 would not reproduce the failure. Based on an erroneous assumption that the initial automatic transfer from Bus 6 to Bus 5 had not occurred, trouble-shooting activities concentrated on breaker 9C. Breaker 9C was removed from Bus 5 and preventive maintenance was performed on this breaker. The breaker's control relay (52X) was replaced during the preventative maintenance. Breaker 9C was reinstalled into the Bus 5 switch-gear and surveillance test 5.1-19 was completed with the MCC-5 ABT functioning as expected.

Following the arrival of the AIT, the licensee initiated a formal root cause evaluation of the MCC-5 ABT failure. Based on conflicting observations as to whether the transfer to Bus 5 did or did not occur during the event, the licensee investigation team examined computer alarm logs and bus voltage traces to ascertain the exact sequence of events. It was then concluded that the initial transfer to Bus 5 had occurred and the subsequent transfer back to Bus 6 had failed. This indicated that the initial troubleshooting activities had focused on the wrong breaker. A failure modes and effects analysis was performed by the licensee and independently verified by the AIT, which concluded that the suspect components were either breaker 11C's control relay, an associated Agastat relay or interconnecting wiring. Both the control relay and the Agastat relay were replaced on July 2, 1993 and set aside for further testing.

The licensee then performed a hand-over-hand wiring check, redlining, and connection integrity check evolution for the interconnections between all components in the MCC-5 ABT scheme in accordance with procedure ST 11.8-35, "Functional Test of MCC-5 Transfer Scheme," on July 4-5, 1993. The AIT witnessed these functional test activities. No wiring errors were identified.

While performing the above wiring check, the licensee's personnel observed that the plunger of the control relay (installed several days earlier) associated with Breaker 9C exhibited a sluggish drop out upon removal of control power from the relay. Since this was identical to one of the suspected component's possible failure modes, the control relay was removed for further testing. This failure mode has reoccurred during subsequent bench testing of this specific relay. Five new control relays from the warehouse were also tested and one relay exhibited the sluggish dropout of the relay plunger. The AIT witnessed a number of bench tests of the 52X relays and observed that it appears their exists an attraction between the plunger and the fix parts of the solenoid. The failure of the 52X plunger to drop out promptly is one possible explanation for the failure of the ABT which occurred on June 27, 1993. If the breaker 11C, 52X relay plunger were to hold up for the 6 seconds required for the emergency diesel generator to re-energize Bus 6, then breaker 11C would not re-close. However, the failure of a 52X relay plunger has only been observed when control power is removed from the solenoid and not during an actual breaker opening. The operation of a breaker tripping open will be accompanied by a mechanical shock of the main breaker contacts opening which would tend to assist dropping out the 52X relay plunger. While the failure of the 52X relay plunger is one possible explanation for the MCC-5 ABT failure on July 27, 1993, it is by no means the positive root cause of this failure. Further testing of the 52X relays plunger sticking was ongoing by the licensee and the relay vendor at the conclusion of this inspection.

Following the completion of procedure ST 11.8-35, the ABT was again functionally tested by securing power to Buses 5 and 6 and verifying the ABT function. These test were conducted in accordance with surveillance test ST 11.7-126, "Functional Test of MCC5 Automatic Bus Transfer (ABT)," and the tests were witnessed by the AIT. Additional tests were conducted to verify that the 52X relays plungers, installed in breakers 9C and 11C, would not stick when control power was removed. The tests energized the 52X relays in breakers 9C and 11C for a long period of time and then removed the control power. These tests were witnessed by the AIT and the solenoid plungers were observed not to stick.

Root Cause

The root cause for this failure has not been positively identified. A formal root cause determination has been completed and (2) components have been identified as being the most likely cause of the failure. These components are an Agastat timing Relay, 62-6A, and the 11C breaker, 52X relay which is an integral part of a Westinghouse DB 25 breakers.

The licensee provided a "Test Plan for Evaluation of Suspect Components," as part of the root cause determination report. The plan provides for extensive cycle testing of the suspected components. Following the cycle testing, the plan requires physical examination of the suspect components. The plan is scheduled for completion within two week after reaching 100% power following startup from the current refueling outage. The plan was reviewed by the AIT and determined to be comprehensive.

2.3.2 Corrective Actions

The licensee's short term, long term and compensatory measures for the MCC-5 ABT failure were provided to the NRC in a letter " Commitments to Test Motor-Control-Center-5," dated July 15, 1993. The licensee has committed to complete the following actions prior to entering Mode 4:

1. Brief all on-shift licensed operators on the significance of a loss of MCC-5 and how to recognize and correct this situation in accordance with Emergency Operating Procedure 3.1-50.

2. Put in-place a procedure for ensuring that any time there is a transfer of MCC-5, a visual verification of the "dropout" of the 52X relay of the open MCC-5 feeder breaker is performed.

3. Place caution tags on each of the breaker trip pushbuttons in the "A" switch-gear room to preclude the potential for lockup of both breakers in the open position. During the inspection, it was identified that if the preferred source breaker was manually tripped, MCC-5 would be de-energized and no automatic transfer would occur. The caution tags were written to inform plant operators of this fact.

These actions were completed prior to the conclusion of this inspection and the actions were verified by the AIT.

The licensee also committed to conduct additional online testing of the ABT. These testing activities are contingent upon receiving approval by the NRC of an amendment to the Technical Specifications. The amendment is required to allow the temporary removal of the control power to breaker 9C. Removal of the control power to the breakers will render the ABT inoperable. The online testing activities are as follows:

1. Disconnect the direct current power to the 52X relay in 480 Volt, Bus 5, compartment 9C. The dropping of the relay will be witnessed visually when the power is disconnected. The frequency of this test will vary starting with weekly tests for four weeks, monthly tests for the next 4 months and then quarterly tests for the remainder of Cycle 18.

2. A functional test of MCC-5 will be conducted any time during Cycle 18 the plant is placed in Mode 5.

The licensee has also committed to the following long-term actions:

1. Conduct an investigation of potential design changes that would increase the reliability of the ABT scheme. Any modifications concluded to be appropriate would be implemented, if possible, during the next refueling outage.

2. Preventative maintenance will be performed on Breakers 9C and 11C each refueling outage in lieu of every other refueling outage as currently required.

3. The licensee will continue to work with the breaker vendor to investigate the root cause of the ABT failure.

2.3.3 Inappropriate Notification of Emergency Classification

The AIT reviewed the licensee's response to the loss of MCC-5 on June 27, 1993 as related to the implementation of the emergency plan. The event was correctly reported to the NRC as an Unusual Event, but was initially, erroneously reported to the State of Connecticut as an Alert. The team reviewed the circumstances involved in this mis-communication to understand how it occurred, and to determine what factors may have contributed to it, including equipment and personnel performance, training, and procedure adequacy.

Background

The Emergency Notification and Response System (ENRS) is a computer based system that automatically provides notification of an emergency event and its details to the licensee staff and offsite emergency response organizations. The ENRS uses pre-formatted electronic voice messages to describe each emergency classification. The pre-formatted messages are customized for each incident when the Shift Supervisor Staff Assistant (SSSA) enters event specific information into the system via a computer terminal. The SSSA also supplements the pre-formatted data with a voice message to briefly describe the incident. The entire message unit is then sent to the radio tower for broadcast to the radio-pagers. The ENRS facilitates data entry through a series of prompts and data input screens. The main data input screen is formatted to replicate the hard copy Incident Report Form from emergency plan implementing procedure (EPIP) 1.5-2 that is filled out by licensed operations and/or shift management personnel, and approved for release. Once reviewed for accuracy and approval, the message form is given to the SSSA, who translates the approved hard copy information into the ENRS to produce the electronic message. In addition to the above electronic voice features, the system also allows operations personnel to broadcast a message directly from the tower.

Event

On June 27, 1993, motor-control-center-5 failed to remain energized during surveillance testing. The operations shift supervisor and the duty officer recognized the loss of MCC-5 as an emergency action level and classified the event as an Unusual Event and entered the emergency plan implementing procedures as necessary to make the required notifications for this event. The event classification was erroneously reported to the state as an Alert at 19:14. Two subsequent emergency notification messages were broadcast over the ENRS in attempts to correct the error at 19:28 and 19:40. A fourth radio-pager message was sent at 19:45 directly over the broadcast tower in an attempt to stop emergency responders who might be in transit to the site or emergency response facilities.

The event was properly classified as an Unusual Event by the Shift Supervisor and the Duty Officer. The information was properly coded on the Incident Notification Form (INF), as approved by the Shift Supervisor. The duty SSSA incorrectly translated the Incident Classification from the form to the ENRS.

The data translation error was made when the SSSA failed to notice that he chose an "Alert" posture code and incident classification from the menu on the data input screen. The SSSA did not adequately verify the information as he was inputing into the ENRS, and in spite of three subsequent opportunities to check the inputs for accuracy and to discover the incorrect Alert classification coded into the electronic massage. It takes about 10 minutes for the SSSA to input the data into the ENRS. During this time the ALERT classification is clearly visible on the terminal screen. The SSSA could have discovered the misclassification at any time during that period had he checked his inputs for accuracy. The SSSA stated that he felt under pressure to process the notification within the 12 minutes required by the procedure, and assumed his inputs were accurate. By not checking the notification message for accuracy, the SSSA failed to meet two specific procedure requirements: (1) Step 6.1.5 of EPIP 1.5-2, "Notification and Communication" requires the SSSA, once the INF data has been input into the ENRS, to "review the entire INF and verify the information is accurate" prior to getting Shift Supervisor permission to release the radio-pager message; and, (2) Step 6.4.3 of NOP 2.16-10, "Operation of the ENRS and Centracom", requires the SSSA to "review the entire recorded INF message to ensure that all data is accurate" prior to releasing the radio-pager message.

The incorrect Alert classification was identified by others in the control room who heard the event notification being broadcast over the pager system. The SSSA received additional assistance to correct the mistake by (i) sending out an "update" message stating that the last event was an Unusual Event and that a response to the plant was not required; and, (ii) sending out a third notification that properly classified the LNP event as an "Unusual Event." Finally, a fourth message was sent out directly to the radio-tower from the Centracom to plant personnel informing them that they need not respond to the plant.

The SSSA provided erroneous meteorological information in the "Alert" notification to the state and local officials. He did this when the ENRS system prompted him for wind speed and direction during the data entry phase of constructing the notification message. All other information prompted by the ENRS was on his incident notification form except the meteorological (MET) data, which is not sent for Unusual Events. MET data is only provided for events classified as Alert or higher. The fact that ENRS was prompting him for MET data for an event he knew was an Unusual Event, should have caused the SSSA to question his inputs and cause him to discover the Alert classification.

The SSSA knew he had to provide all the information that ENRS prompted him for before the system would send the notification message. He did not have the necessary information on the INF. He should have either checked with the Shift Supervisor, or gotten the MET data himself. The SSSA rationalized that MET data is not needed for an Unusual Event message, so he made up the information to satisfy the ENRS prompt. The SSSA thought that it was not important that the MET data was accurate because he thought that the ENRS would not send the MET data as part of the Unusual Event message. The SSSA stated he was overly focused on getting the initial message out within the 12 minutes, and did so at the expense of assuring the accuracy of the information.

The team noted that the meteorological data for the "Alert Update" message sent out at 19:28 also had erroneous meteorological data. This message was prepared by the duty SSSA, with the assistance of an off-duty SSSA and the operations Shift Supervisor. The Shift Supervisor authorized the use of fictitious wind speed and direction in compiling the update message. The Shift Supervisor stated to the team that he did so because (i) it was an expediency to inform licensee and offsite authorities as quickly as possible that the first message was really an Unusual Event - it was important to correct the mis-communication as quickly as possible; and, (ii) the actual meteorological information was not important since the actual event involved no radiological release or other offsite impact.

The licensee's review of the response by state and local authorities to the Alert message at 19:05 was less than expected. The radio-pager message is the official prompt notification of plant events that have the potential to impact the public and which may demand prompt protective measures. State and local communities acknowledge receipt of the radio-pager message by a call-in process whereby they get more detailed information about the event in progress. The licensee noted that 9 of 18 local communities and 3 of 6 state agencies did not perform the call in verification in response to the Alert message at 19:14. The licensee has taken action to address this matter in a letter to the Connecticut State Office of Emergency Management (EP-93-464), dated July 6, 1993.

Corrective Action

The root cause for the mis-communication of the June 27 emergency message was personnel error in failing to follow procedures and exercising attention to detail in the completion of this task. The team concluded that procedures were adequate, and that training was not a factor in the event. The licensee took actions to address a personnel performance issue. The licensee recognized the significance of using incorrect meteorological information on the ENRS messages. The licensee addressed the need for accuracy in this data with all SSSAs and will address this topic with operations personnel.

2.3.4 Equipment Failure History

The Nuclear Plant Reliability Data System was used to identify the failure history of Westinghouse DB type breakers control relays. The search identified approximately 28 reported failures of control relays since 1984. The cause of these failures was generally attributed to dirt, aging, mechanical misalignment, or mechanical binding due to burrs. However, a positive root cause was often not identified. Corrective actions generally included 52X relay replacement, repair or readjustment.

The team also reviewed two licensee event reports (LERs) pertaining to 52X relay failures:

> LER 84-023 from Haddam Neck Plant reported on six incidents of Westinghouse breakers failing to close when required. Five of those failures were directly attributed to 52X relay malfunctions. The sixth breaker failure possibly resulted from a 52X relay malfunction. The main cause of the control relay malfunctions was stated to be dust or dirt accumulation on the plunger and its latch arm assembly. Since the licensee concluded that the malfunctions presented a generic problem in the plant, the immediate action was to inspect and clean all 52X control relays. Westinghouse incorporated an improved description of the adjustment procedure necessary for the 52X relay's mechanical latch/linkage into DB-50 (reactor trip breakers) maintenance manuals but did not included similar information in the maintenance manuals for the DB-25 breakers, which use 52X relays.
>
> LER 92-002 from Oconee Nuclear Station reported the failure of 52X relays on the plant's emergency hydro units' field and field flashing breakers (Westinghouse DB-25s). The 52X relay did not reset until the hydro unit coasted down. A speed switch de-energizes the 52X coil and the plunger falls by gravity to reset the relay. The failure mode, failing to reset, was first discovered in June 1991 on commercial grade 52X relays. The cause of the specific failure mode was not known and the relays were replaced with safety grade relays. On January 28, 1992, a safety grade 52X relay failed to reset. As immediate corrective action the licensee inspected each 52X relay to ensure that they did reset following each shutdown. A design change has now been implemented to replace the electro-mechanical anti-pump scheme provided by the 52X relay with an electrical scheme.

2.3.5 Conclusions

Event

The safety significance of this event was determined to be high. MCC-5 and the associated ABT are required to provide power to the emergency core cooling system (ECCS) valves needed to mitigate the consequences of accidents. If MCC-5 is lost, the normally closed high and low pressure injection valves will not open. The actual risk to the health and safety of the public was low since the reactor was in cold shutdown and the ECCS systems were not required to be operable. However, the reliable operation of MCC-5 and the associate ABT is essential for plant safety.

The team concluded that the actions taken by the operators to restore power to MCC-5 were appropriate. The shutdown cooling system was not lost during this event. The licensee's failure to transmit the correct event notification was the result of an error by a non-licensed Shift Supervisor Staff Assistant (SSSA). The licensed Shift Supervisor had correctly classified this event as an Unusual Event. The SSSA erroneously selected the wrong classification while making the computer entry to transmit the notification and did not identify the error during verification of the message. Licensee actions to address a personnel performance issue and accurate meteorological information were appropriate.

The formal root cause analysis was thorough and identified the error in the original assumption that breaker 9C had failed to close during the event. The team independently verified that the components that were the most likely cause of this event were the breaker 11C 52X control relay, Agastat timing relay 62-6A, the breaker 9C auxiliary switch 52/b contacts, or interconnecting wiring. The hand-over-hand inspection, redlining and continuity check eliminated interconnecting wiring as a potential cause for this failure. Testing and design of the auxiliary relay switch on the 9C breaker eliminated it as a potential cause. The evaluation concluded the malfunction of the 52X relay or the Agastat timer relay was the most likely cause of this event. The team concluded that this event was a due to an intermittent equipment failure of a component(s) in the MCC-5 ABT or the associated breakers and was not the result of performance deficiencies by the plant staff, procedures, or maintenance of the equipment.

Assessment of Corrective Actions

The team also concluded that the short-term corrective actions taken by the licensee were comprehensive. While the root cause evaluation was unsuccessful in identifying a failed component which would account for this failure, it was successful in identifying the suspect components which were subsequently replaced. The compensatory measures taken are adequate to assure reliable operation of the currently installed ABT equipment. The licensee's investigation and proposed actions to address the sticking plunger in the Westinghouse 52X control relay were appropriate.

The long term corrective actions are also appropriate. The commitment to conduct additional testing of the suspected components is essential to exhaust all avenues for determining a root cause for this failure. The proposed engineering evaluation of the ABT design is important to optimize the reliability of this safety significant system. Reducing the breaker preventative maintenance interval to each refueling outage will also enhance breaker performance.

An apparent discrepancy was noted between the Updated Final Safety Analysis Report (UFSAR), Section 8.3.1, and the install configuration of the plants electrical system. The UFSAR states in part that "The Class 1E system has the redundancy, capacity, capability, and reliability to supply power to all safety-related loads. This system ensures a safe plant shutdown to mitigate accident effects, even in the event of a single failure." This statement does not appear to be accurate as related to single failures and MCC-5. The UFSAR does not explicitly discuss single failure vulnerabilities of MCC-5. The licensee stated at the exit meeting that the UFSAR would be reviewed and if appropriate, changes would be made.

The team questioned the applicability of 10CFR 50.46 (d), which explicitly states that the performance of the ECCS system must include in particular Criterion 35 of Appendix A, which requires that the ECCS safety function be accomplished assuming a single failure. The current design of the ECCS system does not satisfy the requirement of Criterion 35 due to the single failure vulnerabilities of MCC-5. The team noted that the Haddam Neck Plant was licensed prior to Appendix A and does not need to meet these criteria. However, the team could not determine if an exemption from 10CFR 50.46 (d) was required in addition to the exemption granted for the single failure of MCC-5 during original plant licensing. This issue is currently under review by the NRC.

3.0 EXIT MEETING

The team met with those denoted in Attachment A, on July 27, 1993, to discuss the preliminary inspection findings which are detailed in this report. The exit meeting was open for public observation and the NRC answered public questions following the exit meeting. The slides used at the exit meeting are provided as Attachment D of this inspection report.

ATTACHMENT A
PERSONS CONTACTED

Connecticut Yankee Atomic Power

* E. Annino	Sr. Analyst - CY
P. Ballote	Generation Test Technician
W. Barton	Engineer
M. Bain	CY Eng. Manager
* W. Becker	Supervisor - ED
M. Brothers	Engineering Supervisor
A. Castagno	NU - Manager Nuclear Information
* D. Dube	PRA Supervisor - NUSCO
* C. Gladding	CY Engineering Manager
* W. Kadlec	Generation Test Supervisor
J. LaPlatney	Operations Manager
T. McDonald	Maintenance Manager
* B. McKenna	Engineer
* R. Morse	Maintenance Engineer
* T. Nichols	CY Maintenance
E. Perkins	Nuclear Licensing Engineer
* G. Pittman	CYPSD - Corp. Eng.
D. Ray	Unit Director
R. Rogozinski	Procurement Engineering Supervisor
* M. Samek	Supervisor - CYPSD
* B. Solomon	Assistant Engineer - Licensing
* J. Stetz	Vice President - Haddam Neck Station
* R. Trejo	Sr. Nuclear Information Rep. - CY
R. Willis	Shift Supervisor

U. S. Nuclear Regulatory Commission

* J. Andersen	NRC Project Manager
* C. Miller	NRC Deputy Director, DRS
* P. Habighorst	Resident Inspector - Haddam Neck
* T. Ulses	NRC Reactor Engineer

Asterisk (*) denotes those present at the exit meeting.

ATTACHMENT B

MCC-5 ABT FUNCTIONAL DESCRIPTION

A typical transfer would occur in the following sequence with the assumption that Bus 6 is the preferred source and is initially energized and connected to MCC-5 through Breaker 11C (See Figure 5):

1. The automatic transfer starts when Bus 6 becomes de-energized. Agastat 62-6A senses the loss of voltage on the bus and trips Breaker 11C after a one second delay through its contacts 6-2.

2. If Bus 5 is energized, the control relay 52X for Breaker 9C picks up through contacts 6-2 of Agastat 62-5B and contacts 52/b of Breaker 11C.

3. The closing coil 52CC for Breaker 9C is energized through contacts from 52X. Breaker 9C closing mechanically causes the 52X contacts to then open.

4. The transfer has thus taken place and the 52X control relay for Breaker 9C remains energized as long as voltage remains on Bus 5 and Breaker 11C remains open or in the test or racked-out position. The control relay is in the anti-pump position and prevents further attempts to energize its close coil 52CC.

If Voltage is restored to Bus 6, a retransfer will occur in the following sequence since it is the preferred source:

1. When voltage is restored, Agastat 62-6A picks up and Breaker 9C's trip coil is energized through contacts 5-3 of 62-6A and contacts A11-B11 of the selector switch.

2. When Breaker 9C opens, the control relay for Breaker 11C is energized through contacts 6-4 of Agastat relay 62-6A and Breaker 9C contacts 52/b.

3. The closing coil 52CC for Breaker 11C is then energized through contacts from 52X. The control relay for Breaker 9C also becomes de-energized when Breaker 11C closes.

4. The retransfer has taken place and the 52X relay for Breaker 11C now remains energized.

ATTACHMENT C

AUGMENTED INSPECTION TEAM CHARTER

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

JUN 29 1993

Docket No. 50-213

MEMORANDUM FOR: Marvin W. Hodges, Director, Division of Reactor Safety

FROM: Thomas T. Martin, Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER FOR REVIEW OF UNUSUAL EVENTS DURING ELECTRICAL TESTING AT HADDAM NECK

On June 22, 26 and 27, 1993, Haddam Neck station declared Unusual Events (UEs) as a result of problems experienced during electrical system testing. Due to the nature of these events, I have determined that an Augmented Inspection Team (AIT) inspection should be conducted to review the causes, safety implications, and associated licensee actions which led to (or resulted in) the repeated loss of offsite power, and loss of power to a vital motor control center (MCC-5).

The Division of Reactor Safety (DRS) is assigned the responsibility for the overall conduct of this Augmented Inspection. Jim Trapp, Team Leader, DRS, is appointed as Augmented Inspection Team Leader. Other AIT members are identified in Enclosure 2. The Division of Reactor Projects (DRP) is assigned the responsibility for resident and clerical support, as necessary; and the coordination with other NRC offices, as appropriate. Further, the Division of Reactor Safety, in coordination with DRP, is responsible for the timely issuance of the inspection report, the identification and processing of potentially generic issues, and the identification and completion of any enforcement action warranted as a result of the team's review.

Enclosure 1 represents the charter for the Augmented Inspection Team and details the scope of the inspection. The inspection shall be conducted in accordance with NRC Management Directive (MD) 8.3, NRC Inspection Manual 0325, Inspection Procedure 93800, Regional Office Instruction 1010.1, and this memorandum. Concerns have been identified with the repetitive loss of offsite power, the apparent impact of non-safety related protective features on vital power supplies, a possible lack of redundancy with respect to safety-related loads powered by MCC-5, and the miscommunication of the June 27 event classification to the state. An AIT to review these events is appropriate since they involve significant system interactions and unknown underlying root causes. The NRC staff needs to fully understand the causes of these events, and determine whether further actions will be required.

Thomas T. Martin

Thomas T. Martin
Regional Administrator

Enclosures:
1. Augmented Inspection Team Charter
2. Team Membership

cc w/encls:
J. Taylor, EDO
J. Sniezek, OEDO
T. Murley, NRR
J. Partlow, NRR
J. Calvo, NRR
C. Rossi, NRR
J. Stolz, PD I-4, NRR
F. Miraglia, NRR
C. McCracken, NRR
F. Rosa, NRR
W. Russell, NRR
J. Wiggins, NRR
A. Thadani, NRR
B. Grimes, NRR
J. Roe, NRR
E. Jordan, AEOD
D. Ross, AEOD
D. Wheeler, OEDO
W. Kane, DRA, RI
D. Cooper, DRP, RI
W. Lanning, DRP, RI
R. Blough, DRP, RI
L. Doerflein, DRP, RI
T. Shedlosky, DRP, RI
C. Hehl, DRSS, RI
S. Shankman, DRSS, RI
W. Raymond, SRI, Haddam Neck
A. Wang, PD I-4, NRR
F. Burrows, EELB, NRR
J. Durr, DRS, RI
L. Bettenhausen, DRS, RI
J. Trapp, DRS, RI
K. Abraham, PAO, RI
M. Miller, SLO, RI

ENCLOSURE 1

Haddam Neck Station

Review of Unusual Events During Electrical Testing at Haddam Neck

Augmented Inspection Team (AIT) Charter

The general objectives of this AIT are to:

1. Conduct a thorough and systematic review of the circumstances surrounding the June 22 and June 26 loss of off-site power events, and the June 27 loss of power to safety bus MCC-5 event.

2. Develop a detailed sequence of events for each loss of off-site power and the loss of bus MCC-5.

3. Collect, analyze, and document relevant factual information to determine the causes, conditions, and circumstances pertaining to each event.

4. Evaluate the licensee's review of and response to each event and the implemented corrective actions, including providing the state an inappropriate EAL on June 27, 1993.

5. Assess the safety significance of each event and communicate to Regional and Headquarters management the facts and safety concerns related to problems identified, including single failure vulnerabilities and impact of non-safety related equipment on safety systems.

6. Evaluate the knowledge and performance of licensee staff during these events.

7. Evaluate the maintenance testing and any changes made to the design which may have contributed to this failure.

8. Prepare a report documenting the results of this review for signature of the Regional Administrator within thirty days of the completion of the inspection.

ENCLOSURE 2

Haddam Neck AIT Membership

Jim Trapp, AIT Leader, Division of Reactor Safety (DRS), Region I (RI)

William Raymond, Senior Resident Inspector, Haddam Neck, DRP, RI

Thomas Shedlosky, Project Engineer, DRP, RI

Fred Burrows, NRR

Other NRC personnel, consultants, or contractors will be engaged in this AIT, as needed.

ATTACHMENT D

AUGMENTED INSPECTION TEAM

EXIT MEETING SLIDES

HADDAM NECK
LOSS OF OFFSITE POWER
JUNE 22, 1993 EVENT

EVENT DESCRIPTION

- PLANT ELECTRICAL SYSTEM CONFIGURED TO SUPPORT BREAKER FAILURE TESTING OF TIE BREAKER 389T399.
- TEST UNEXPECTEDLY OPENS BREAKER 3891 AND ISOLATES OFFSITE POWER FROM THE PLANT.
- THE EMERGENCY DIESEL GENERATORS AUTOMATICALLY SUPPLY POWER TO THE PLANT.

ROOT CAUSE

- WIRING ERROR WHICH OCCURRED DURING OR SHORTLY FOLLOWING PLANT CONSTRUCTION.

CORRECTIVE ACTIONS

- TECHNICAL JUSTIFICATION DEVELOPED FOR LEAVING PLANT CONFIGURATION AS IS.
- REVIEW BREAKER TRIP CIRCUIT WIRING DURING THE NEXT REFUELING OUTAGE.

2

HADDAM NECK
AUGMENTED INSPECTION TEAM
PUBLIC EXIT MEETING AGENDA

JULY 27, 1993

1. EXIT MEETING BETWEEN NRC AND LICENSEE.

2. NRC ADDRESS PUBLIC QUESTIONS REGARDING TEAM FINDINGS.

EVENTS

- LOSS OF OFFSITE POWER ON JUNE 22, 1993

- LOSS OF OFFSITE POWER ON JUNE 26, 1993

- LOSS OF MOTOR CONTROL CENTER 5 ON JUNE 27, 1993

1

HADDAM NECK
LOSS OF OFFSITE POWER
JUNE 22, 1993 EVENT
CONTINUED

ASSESSMENT OF EVENT

- PLANT EQUIPMENT FUNCTION AS EXPECTED FOLLOWING THE EVENT.
- OPERATOR RESPONSE TO THE EVENT WAS GOOD.
- NOTIFICATION OF AN UNUSUAL EVENT WAS APPROPRIATE.
- TECHNICAL JUSTIFICATION ADEQUATELY SUPPORTS LEAVING WIRING ERROR AS IS.
- REVIEW OF TRIP LOGIC WIRING DURING THE NEXT REFUELING OUTAGE IS APPROPRIATE.

HADDAM NECK
LOSS OF OFFSITE POWER
JUNE 26, 1993 EVENT

EVENT DESCRIPTION

- SURVEILLANCE TEST BEING PERFORMED WHICH SIMULATES PARTIAL LOSS OF OFFSITE POWER.
- WHEN BREAKER 3891 WAS OPENED BREAKER 3991 UNEXPECTEDLY OPENED.
- THE EMERGENCY DIESEL GENERATORS AUTOMATICALLY SUPPLY POWER TO THE PLANT.

ROOT CAUSE

- BLOWN FUSE IN VOLTAGE SENSING CIRCUIT.

CORRECTIVE ACTIONS

- REPLACED FUSE.
- REVISED TEST PROCEDURE.

HADDAM NECK
LOSS OF OFFSITE POWER
JUNE 26, 1993 EVENT
CONTINUED

ASSESSMENT OF EVENT

- GENERALLY PLANT EQUIPMENT FUNCTION AS EXPECTED FOLLOWING THE EVENT.
- OPERATOR RESPONSE TO THE EVENT WAS GOOD.
- NOTIFICATION OF AN UNUSUAL EVENT WAS APPROPRIATE.
- THIS EVENT ROOT CAUSE IS UNRELATED TO FIRST EVENT.
- THE IDENTIFIED VOLTMETER DEFICIENCY SHOULD HAVE BEEN INCLUDED IN THE WORK CONTROL SYSTEM.
- CAUSE OF FUSE FAILURE MOST LIKELY MAINTENANCE ON ASSOCIATED EQUIPMENT.
- THE CORRECTIVE ACTIONS TAKEN FOR THIS EVENT WERE APPROPRIATE.

5

HADDAM NECK
LOSS OF MOTOR CONTROL CENTER 5
JUNE 27, 1993 EVENT

EVENT DESCRIPTION

- SURVEILLANCE TEST BEING PERFORMED WHICH SIMULATES PARTIAL LOSS OF OFFSITE POWER.
- MCC-5 TRANSFERRED TO BUS 5 FOLLOWING LOSS OF POWER ON BUS 6.
- MCC-5 IS DE-ENERGIZED WHEN AUTOMATIC BUS TRANSFER FAILS TO TRANSFER BACK TO BUS 6.
- OPERATORS MANUALLY CLOSE BREAKER TO ENERGIZE MCC-5 FROM BUS 5.
- AN ERRONEOUS EVENT CLASSIFICATION OF AN ALERT IS SENT TO THE STATE AND TOWNS.

ROOT CAUSE

- NOT POSITIVELY IDENTIFIED. TWO SUSPECTED COMPONENTS HAVE BEEN IDENTIFIED.

6

LOSS OF MOTOR CONTROL CENTER 5
JUNE 27, 1993 EVENT
CONTINUED

CORRECTIVE ACTIONS

SHORT TERM

- REPLACED SUSPECT COMPONENTS.
- PERFORMED A FORMAL ROOT CAUSE EVALUATION.
- CONDUCTED A WIRING CHECK OF ABT SYSTEM.

COMPENSATORY MEASURES

- ADDITIONAL ABT TESTING.
- CAUTION TAG ON BREAKERS 9C AND 11C.
- CONDUCT OPERATOR TRAINING.

LONG TERM

- EVALUATE AUTOMATIC BUS TRANSFER SYSTEM DESIGN.
- CONDUCT PREVENTATIVE MAINTENANCE ON 9C AND 11C BREAKERS EACH REFUELING OUTAGE.

7

LOSS OF MOTOR CONTROL CENTER 5
JUNE 27, 1993 EVENT
CONTINUED

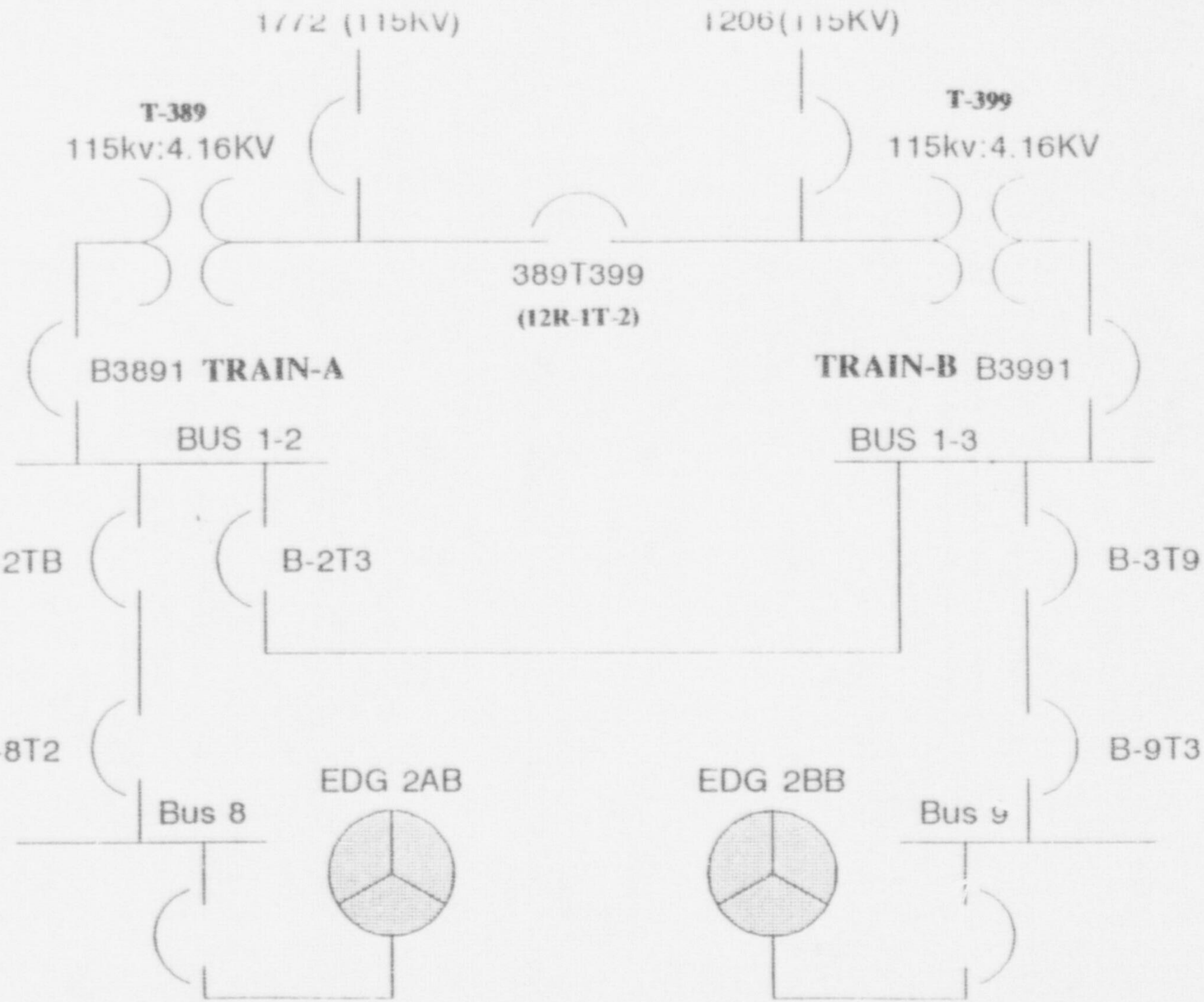
ASSESSMENT OF EVENT

- THE FUNCTION OF MCC-5 IS VERY SIGNIFICANT TO OVERALL PLANT SAFETY.
- TEAM INDEPENDENTLY VERIFIED MOST LIKELY CAUSE OF FAILURE.
- THE EVENT CLASSIFICATION ERROR WAS AN INDIVIDUAL PERFORMANCE ISSUE.
- TROUBLE-SHOOTING AND TESTING CONDUCTED WAS APPROPRIATE.
- ACTIONS TAKEN TO RESTORE MCC-5 WERE APPROPRIATE.
- THE FORMAL ROOT CAUSE EVALUATION WAS THOROUGH.
- SHORT TERM CORRECTIVE ACTIONS TAKEN WERE APPROPRIATE.
- COMPENSATORY MEASURES ARE APPROPRIATE.
- ENGINEERING EVALUATION OF DESIGN.

8

SIMPLIFIED ELECTRICAL SYSTEM DIAGRAM

FIGURE 1



BUS 1-3 PT CIRCUIT & UNDERVOLTAGE TRIP SCHEME

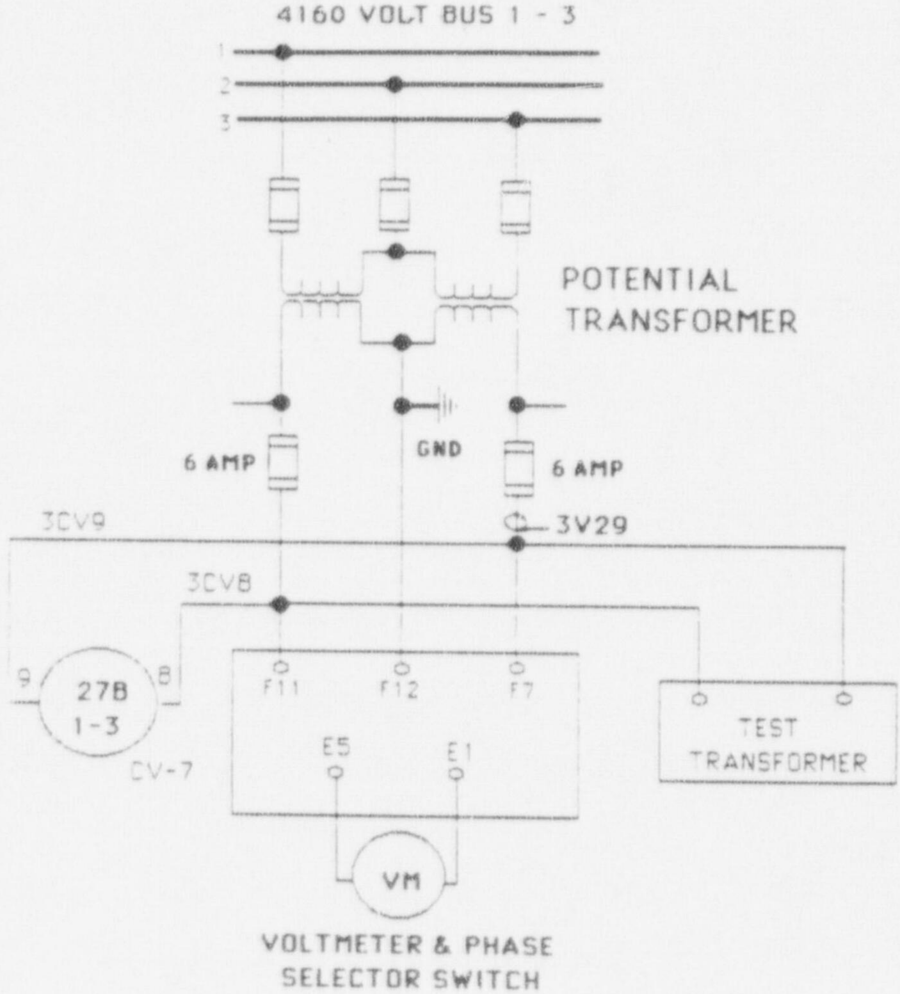
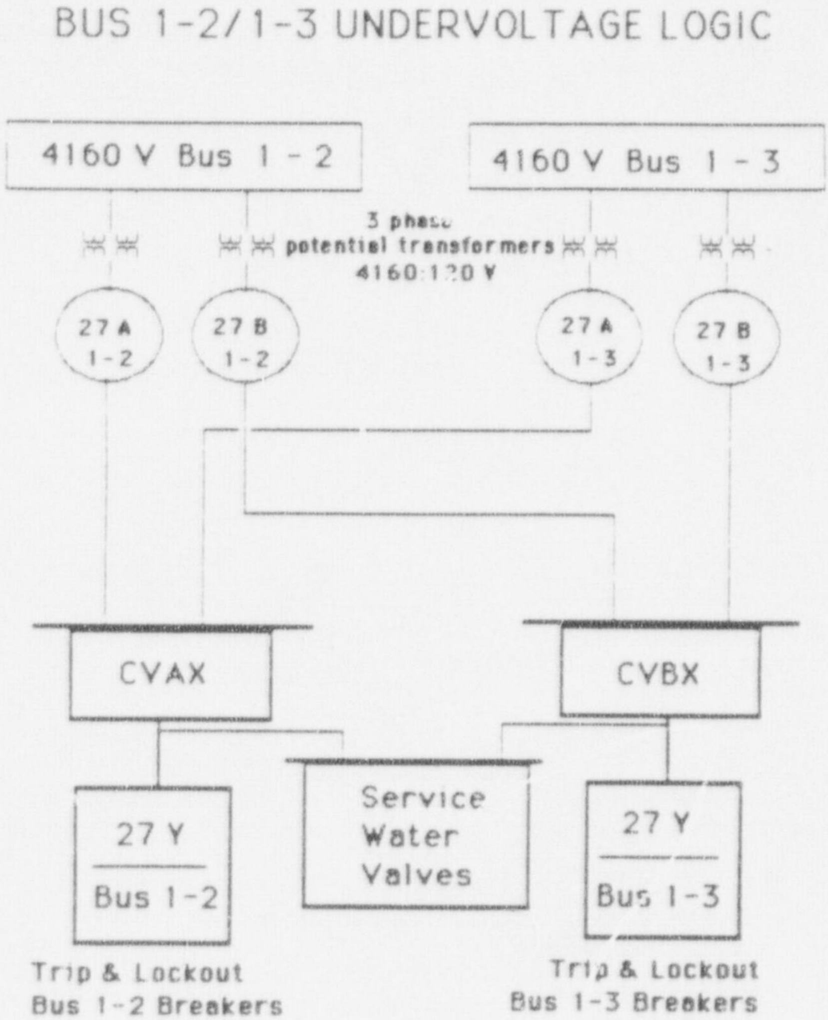
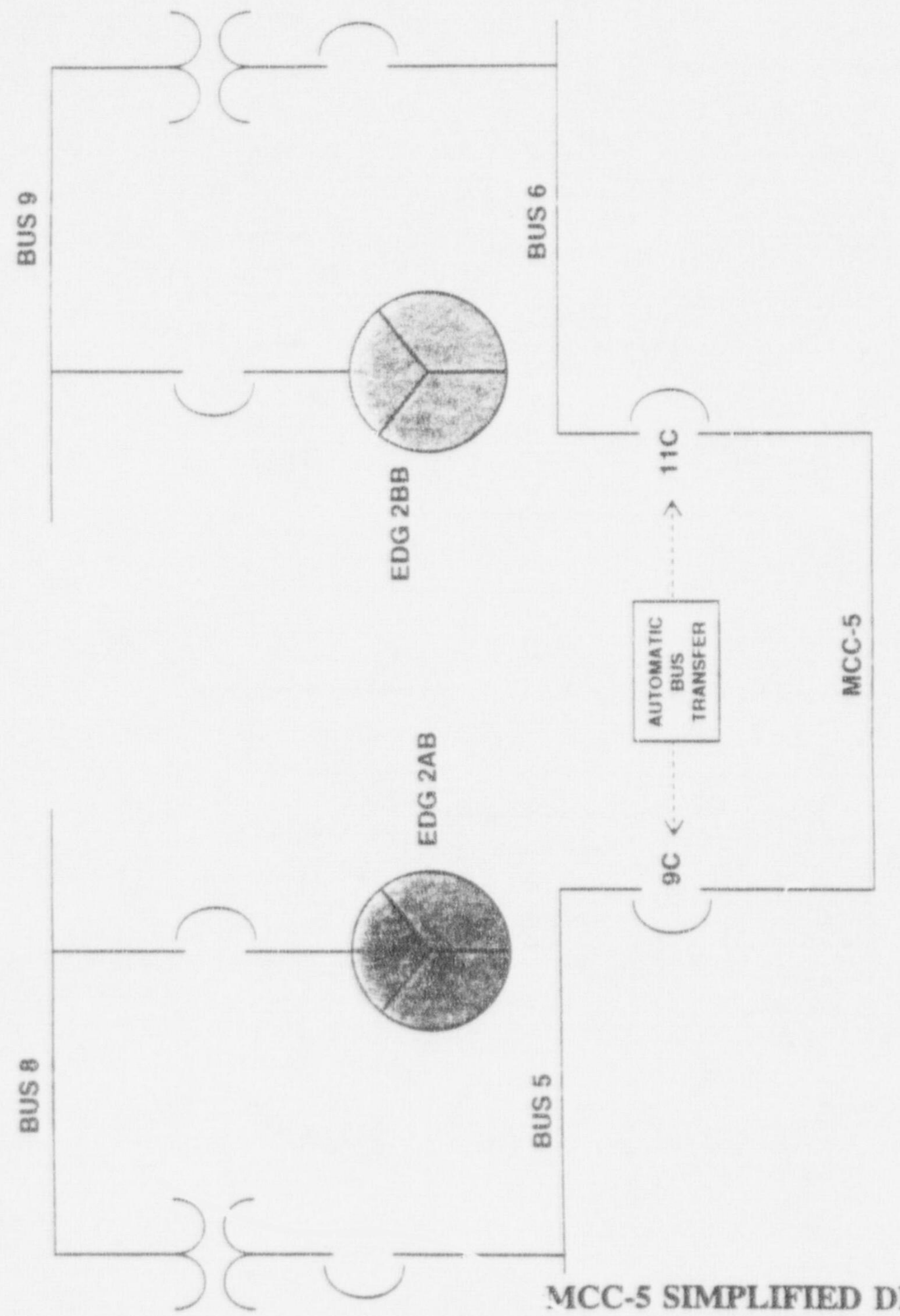


FIGURE 2



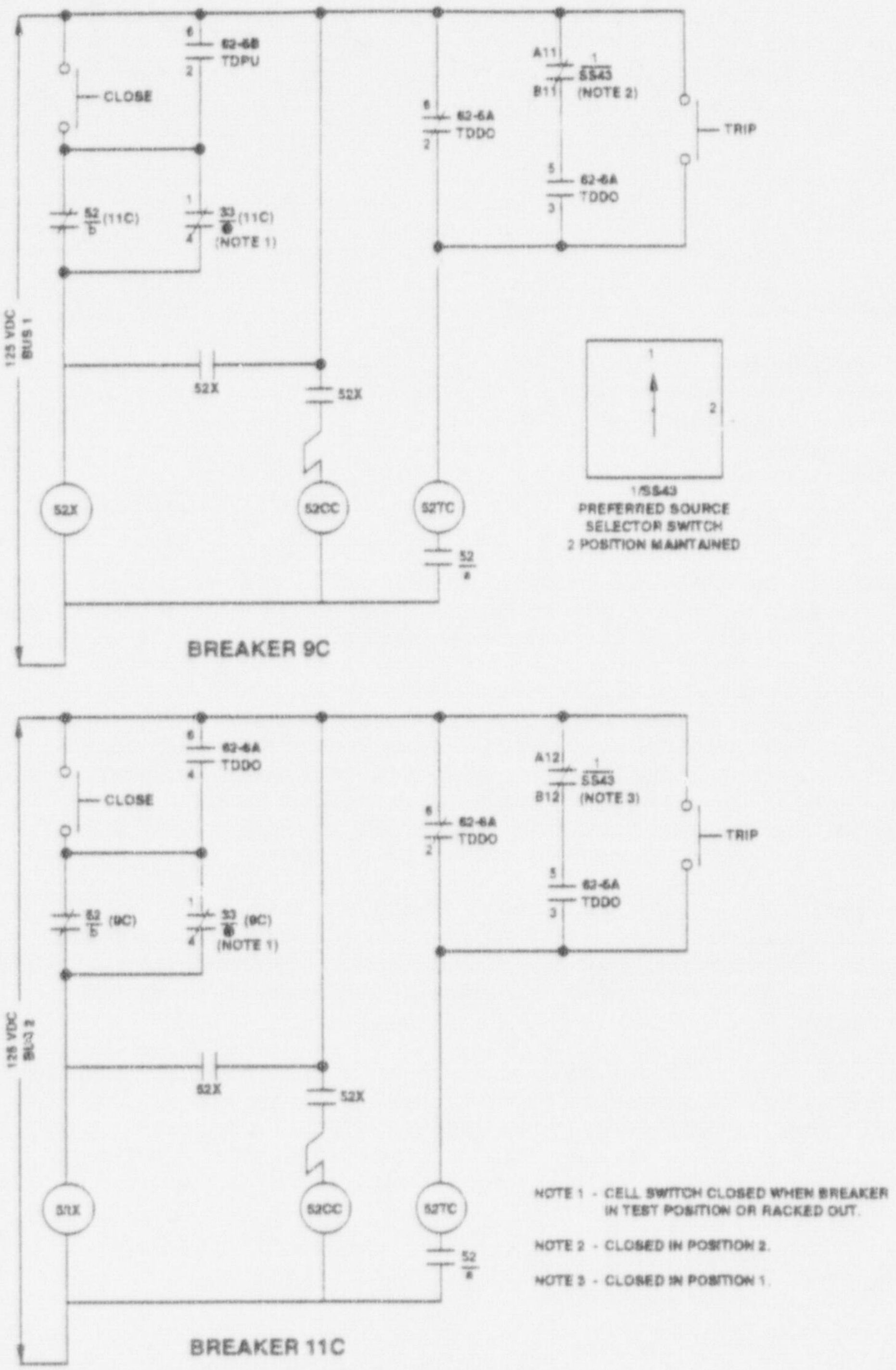
JUNE 26 LOSS OF POWER EVENT

FIGURE 3



MCC-5 SIMPLIFIED DIAGRAM

FIGURE 4



ABT LOGIC DIAGRAM

FIGURE 5

AUG 1 6 1993

Docket No. 50-213

Mr. John F. Opeka
Executive Vice President - Nuclear
Connecticut Yankee Atomic Power Company
P. O. Box 270
Hartford, Connecticut 06141-0270

Dear Mr. Opeka:

SUBJECT: NRC AUGMENTED INSPECTION TEAM (AIT) REGARDING TWO LOSS OF OFFSITE POWER EVENTS AND THE LOSS OF MOTOR-CONTROL-CENTER-5 NRC REPORT NO. 50-213/93-80

The enclosed report refers to the NRC Augmented Inspection Team (AIT), led by Mr. James Trapp of this office, on June 30 through July 9, 1993, at the Haddam Neck Plant in Haddam, Connecticut. The purpose of this inspection was to review the circumstances regarding two separate loss of offsite power events, and a loss of motor-control-center-5 (MCC-5) that occurred during the conduct of test activities. At the conclusion of the inspection, the team findings were discussed with Mr. Stetz and members of your staff at an exit meeting that was open for public observation on July 27, 1993.

The scope of the inspection included developing a detailed event description, evaluating the root causes for the events, assessing the effectiveness of corrective actions, and evaluating the safety significance of each event. The inspection consisted of selective examination of procedures and representative records, observations of testing and inspections, and interviews with personnel.

The loss of offsite power events were significant because they caused a temporary loss of shutdown cooling and the loss of offsite power is a precursor to station blackout. The reliable operation of MCC-5 is vital to plant safety because both trains of emergency core cooling system injection valves are powered from this motor-control-center. Based on the significance of these events, all of which occurred in a short time period, the NRC dispatched an AIT.

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Mr. John F. Opeka 2

The root causes for the June 22 and June 26, 1993, loss of offsite power events were positively identified as a wiring error and a blown fuse, respectively. For both events, the operator actions to mitigate the consequences of the events were appropriate. The corrective actions taken in response to these events were reviewed by the AIT and determined to be acceptable. The NRC team concluded that these events were the result of defective nonsafety-related equipment and were not the result of recent performance deficiencies by plant staff or procedures.

The root cause for the June 27, 1993, failure of the MCC-5 automatic bus transfer scheme was not positively identified. Although the root cause was not identified, two highly suspect components were identified and replaced. Your corrective actions and compensatory measures taken to ensure the reliability of MCC-5 were outlined in your letter to the NRC, dated July 15, 1993, "Commitments to Test Motor-Control-Center-5." We have reviewed these commitments and determined that the proposed actions and compensatory measures are appropriate. While trouble-shooting the automatic bus transfer (ABT) failure, your staff identified a potential generic problem with the Westinghouse DB 25 breaker, 52X relays. At the conclusion of this inspection, this potentially generic breaker failure concern was still under review by your staff and the breaker vendor. We expect that this issue will be resolved and appropriate actions will be taken in an expeditious manner. In addition, your letter states that you plan to conduct a review of potential design changes to the ABT which could improve the reliability of this scheme. We request that you provide the results of this design review and the schedule for implementing any design changes identified to the Region I Regional Administrator.

The NRC team also noted two issues regarding the licensing basis of MCC-5. The updated UFSAR, Section 8.3, states, in part, that "The Class 1E system has the redundancy, capacity, capability, and reliability to supply power to all safety-related loads. This system ensures a safe plant shutdown to mitigate accident effects, even in the event of a single failure." This statement does not appear to be accurate as related to single failures and MCC-5. In addition, the team questioned the applicability of 10 CFR 50.46(d), which explicitly states that the performance of the emergency core cooling system (ECCS) system must include in particular Criterion 35 of Appendix A, which requires that the ECCS safety function be accomplished assuming a single failure. The current design of the ECCS system does not satisfy the requirement of Criterion 35 due to the single failure vulnerabilities of MCC-5. While the team noted that an exemption had been granted by the NRC for the MCC-5 single failure vulnerability during original plant licensing, an explicit exemption from the 50.46 requirement was not apparent to the team. Both of these issues are currently being reviewed by the NRC.

In accordance with 10 CFR 2.790 of the Commission's regulations, a copy of this letter and the enclosed inspection report will be placed in the NRC Public Document Room.

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We will gladly discuss any questions you have concerning this inspection.

Sincerely,

Marvin W. Hodges

Marvin W. Hodges, Director
Division of Reactor Safety

Enclosure: NRC Region I Inspection Report No. 50-213/93-80

cc w/encl:
W. D. Romberg, Vice President, Nuclear, Operations Services
J. P. Stetz, Vice President, Haddam Neck Station
G. H. Bouchard, Director, Nuclear Quality Services
D. J. Ray, Unit Director
R. M. Kacich, Director, Nuclear Licensing
Gerald Garfield, Esquire
Nicholas Reynolds, Esquire
K. Abraham, PAO (2)
Public Document Room (PDR)
Local Public Document Room (LPDR)
Nuclear Safety Information Center (NSIC)
NRC Resident Inspector
State of Connecticut SLO

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AUG 1 6 1993

Mr. John F. Opeka 4

bcc w/encl:
Region I Docket Room (with concurrences)

bcc w/encl **(VIA E-MAIL)**:
J. Stolz, NRR/PD I-4
V. McCree, OEDO
A. Wang, PM, NRR

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Trapp	Durr	Hodges	Martin	Kane
8/10/93	8/11/93	8/11/93	8/ /93	8/ 12 /93

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AIT No. 412/93-81
Beaver Valley Unit 2

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

DCD (OWEN)
P1-37 / IE10

DEC 21 1993

Docket No. 50-412

Mr. J. D. Sieber
Senior Vice President
Nuclear Power Division
Duquesne Light Company
Post Office Box 4
Shippingport, Pennsylvania 15077

Dear Mr. Sieber:

SUBJECT: NRC AUGMENTED INSPECTION TEAM (AIT) REGARDING THE FAILURE OF THE EMERGENCY DIESEL GENERATOR LOAD SEQUENCERS NRC INSPECTION REPORT 50-412/93-81

The enclosed report refers to the NRC Augmented Inspection Team (AIT), led by Mr. James Trapp of this office, on November 9-19, 1993, at the Unit 2, Beaver Valley Power Station in Shippingport, Pennsylvania. The purpose of this inspection was to review the circumstances regarding the failure of both trains of the emergency diesel generator load sequencers. At the conclusion of the inspection, the team findings were discussed with you and members of your staff at an exit meeting that was open for public observation on December 2, 1993.

The scope of the inspection included developing a detailed event description, evaluating the root causes for the events, assessing the effectiveness of corrective actions, and evaluating the safety significance of the event. The inspection consisted of selective examination of procedures and representative records, observations of testing and inspections, and interviews with personnel.

The failure of both emergency diesel generator load sequencers would prevent automatic initiation of the emergency core cooling systems in the event of an accident with a loss of offsite power. The failure of both load sequencers was a significant event because a common cause resulted in the failure of multiple trains of a system designed to mitigate the consequences of an accident. Based on the safety significance of this event, the NRC dispatched an AIT.

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Duquesne Light Company 2

The cause for the failure of the load sequencers was determined to be a malfunction of digital microprocessor based timer/relays. The malfunction in the timer/relays was caused by voltage spikes induced when auxiliary relays in the load sequencer circuits were deenergized. Several diodes were installed across relay coils in the load sequencer circuits to reduce the magnitude of the voltage spikes. The AIT reviewed your corrective actions and concluded that the installation of the diodes was an acceptable response to this failure.

The team concluded that the root cause of the failures was inadequate design control. The modification process that installed the microprocessor based timer/relays in 1990 did not place adequate control on the selection and review for suitability of the new timer/relays. The susceptibility of microprocessor based equipment to voltage disturbances and electromagnetic interference was well known at the time of this design change. It does not appear that adequate detail was provided in the design specification generated for the timer/relays or in the commercial grade qualification testing for these components. Weak design control was also cited as the cause for the failure of six load sequencer timer/relays during the previous failure of the load sequencers in 1992. We are also concerned that during the installation of the diodes, a malfunction was identified during post modification testing with the starting sequence step of the auxiliary feedwater pump. This malfunction required additional design changes to the sequencer and pump starting logic.

Based on the potential of recurring design control issues and the significance of this event, we are planning to schedule an enforcement conference to discuss the circumstances surrounding this issue. The details and schedule for the enforcement conference will be provided in a separate correspondence.

In accordance with 10 CFR 2.790 of the Commission's regulations, a copy of this letter and the enclosed inspection report will be placed in the NRC Public Document Room.

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

Charles L. Miller

Charles L. Miller, Acting Deputy Director
Division of Reactor Safety

Enclosure: NRC Region I Inspection Report No. 50-412/93-81

DEC 2 1 1993

Duquesne Light Company 3

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U. S. NUCLEAR REGULATORY COMMISSION
REGION I
AUGMENTED INSPECTION TEAM REPORT

INSPECTION OF EMERGENCY DIESEL GENERATOR
LOAD SEQUENCER FAILURES

REPORT/DOCKET NOS.	50-412/93-81
LICENSE NO.	NPF-73
LICENSEE:	Duquesne Light Company One Oxford Center 301 Grant Street Pittsburgh, PA 15279
FACILITY:	Beaver Valley Unit 2
INSPECTION DATES:	November 9-19, 1993
INSPECTORS:	J. Calvert, Reactor Engineer, RI S. Greenlee, Beaver Valley, Resident Inspector E. Lee, Electrical Engineer, NRR R. Skokowski, Reactor Engineer, RI

TEAM LEADER: JM Trapp 12-13-93
James M. Trapp, Team Leader Date
Engineering Branch, DRS

APPROVED BY: Jacque P. Durr 12/13/93
Jacque P. Durr, Chief Date
Engineering Branch, DRS

EXECUTIVE SUMMARY

The scope of the Augmented Inspection Team (AIT) inspection was provided by the Region I Regional Administrator in the Augmented Inspection Team Charter. The team was tasked with conducting a detailed review of the circumstances surrounding the failure of both emergency diesel generator load sequencers during routine surveillance testing. Specifically, the team was tasked with developing a detailed sequence of events, evaluating the root cause determination, assessing the effectiveness of the corrective actions, and evaluating the safety significance of the event.

The emergency diesel generator load sequencers automatically place vital safety-related equipment in service if normal power is lost to the emergency busses. Following restoration of power to the emergency busses by the emergency diesel generators, the load sequencer timer/relays are used to load safety-related equipment onto the emergency busses in discrete timed steps. The original load sequencers used electro-mechanical timer/relays to generate the timed steps. The electro-mechanical timer/relays were replaced with digital microprocessor based timer/relays during the second refueling outage, in November 1990. During the third refueling outage, in April 1992, routine surveillance tests identified three of the eight microprocessor timer/relays in each sequencer train had failed. The failures were caused by a modification made to the timer/relays that continuously energized the clock circuits. The root cause for the failures was inadequate design control. The NRC conducted an enforcement conference regarding this failure and issued a Severity Level III violation and a Civil Penalty (NRC Inspection Reports 50-412/92-07 and 50-412/93-22). The failed timer/relays were replaced and the clock circuits were appropriately modified such that the microprocessor timer/relays were only energized during sequencer operation.

On November 4, 1993, during the performance of the Operating Surveillance Test 36.3, "Emergency Diesel Generator Automatic Test," the Train-A, 2-1 emergency diesel generator (EDG) load sequencer failed to automatically load safety-related equipment onto the emergency bus. Subsequent bench testing conducted with the suspect relays was not successful in identifying the cause of the failure. An evaluation of the sequencer logic circuit by the licensee's engineering staff identified two relays, one in the sequencer circuit and one in the solid state protection system, whose malfunction had the potential to cause the symptoms observed during the surveillance test. Both suspect relays were replaced and the surveillance test was successfully repeated on November 5, 1993.

On November 6, 1993, during the performance of the Operating Surveillance Test 36.4, "Emergency Diesel Generator Automatic Test," the Train-B, 2-2 emergency diesel generator load sequencer failed to automatically load safety-related equipment onto the emergency bus. Diagnostic test equipment had been installed on the load sequencer and provided pertinent information on the failure mode. The cause of the sequencer failure was a failed safety injection reset microprocessor timer/relay (762EGSBA). This timer/relay resets the load sequencer when a safety injection signal occurs during a loss of offsite power event. A contact from this timer/relay failed to open, which caused the load sequencer to "lock-up" and fail to automatically load safety-related equipment onto the emergency bus.

The failure of both emergency diesel generator load sequencers would prevent automatic initiation of the emergency core cooling system in the event of an accident with a loss of normal power. In the event that the load sequencers were to malfunction during an accident with a loss of normal power, manual operator actions, in accordance with the emergency operating procedures, would be required to mitigate the consequences of the event. However, for some postulated accidents, manual operator actions might not have been adequate to satisfy the design criteria for the emergency core cooling systems. The team concluded that the common cause failure of multiple trains of a safety system required to mitigate the consequences of an accident was a significant event.

The microprocessor operated timer/relays failed due to voltage spikes introduced through the timer/relay contacts. The voltage spikes were generated by the auxiliary relays that are controlled by the timer/relays. These spikes were generated when the electrical circuit to the coil of an auxiliary relay were opened, resulting in the generation of an "inductive kick," or voltage spike. The "lock-up" of the microprocessors resulted in the failure of the timer/relays. The failure of the timer/relays caused the malfunction of the load sequencers. The exact failure mechanism internal to the microprocessors was not known at the conclusion of this inspection.

A modification of the emergency diesel generator sequencers was implemented to reduce the magnitude of the voltage spikes. The modification installed diodes around the auxiliary relays to reduce the magnitude of the voltage spikes. Nine voltage spike suppression diodes were installed in each emergency diesel generator load sequencer. The post modification testing identified a deficiency with the installation of the diodes. The installation of the diodes increased the drop-out time of the relays, which caused the auxiliary feedwater pump to start at the wrong sequence step. The auxiliary feedwater pump starting circuits and the sequencer logic circuits were modified to correct this problem.

The team concluded that the modification that installed the microprocessor timer/relays was inadequate. The design control for the selection and review for suitability of the Automatic Timer and Controls Company (ATC) timer/relays for this application was not adequate. The modification design inputs should have identified the potential for voltage spiking by the auxiliary relays. This design input should then have been translated into the equipment specification and the dedication testing specification. The delay in auxiliary relay drop-out time caused an auxiliary feedwater pump to start at the wrong sequence step following the installation of the diodes. Further design changes were required to correct this problem. The team concluded that the implications of the installation of the diodes on relay timing was not thoroughly evaluated. The team concluded that the actions taken to correct the auxiliary feedwater pump starting logic problem and the installation of diodes to suppress voltage spikes were acceptable.

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DETAILS

1.0 INSPECTION SCOPE

The scope of the Augmented Inspection Team (AIT) inspection was provided by the Region I Regional Administrator in the Augmented Inspection Team Charter (Attachment 1). Generally, the team was tasked with conducting a detailed review of the circumstances surrounding the failure, during routine surveillance testing, of both the Train-A and Train-B emergency diesel generator load sequencers. Specifically the team was tasked with:

- Conducting a thorough and systematic review of the circumstances surrounding the failure of the diesel generator load sequencers.

- Collecting, analyzing and documenting factual information to determine the causes, conditions, and circumstances pertaining to the failures, including the adequacy of commercial dedication qualification testing of the relays and the adequacy of the licensee's corrective actions in response to a previous failure of this circuitry.

- Evaluating modification controls, design changes, and surveillance testing which may have contributed to the failures.

- Evaluating the licensee's review of and response to the failures, including implemented and proposed corrective actions.

- Assessing the safety significance of the failures and communicating to Regional and Headquarters NRC management the facts and safety concerns related to problems identified, including single failure vulnerabilities and impact on other safety-related equipment, generic implications and the need for communication of generic issues to other licensees.

In addition to the team charter, the NRC issued a Confirmatory Action Letter (1-93-020) on November 9, 1993, to confirm verbal commitments made by the licensee to the NRC regarding this event. Specifically, the letter documented the following actions: (1) The quarantine and suspension of testing of the relays and components, which may have caused the failure of the emergency diesel generator load sequencers, until resumption is authorized by the AIT team leader; and (2) Maintain Unit 2 in the cold shutdown mode until you receive authorization from the Regional Administrator, NRC Region I.

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2.0 DETAILED INSPECTION FINDINGS

2.1 Background

The emergency diesel generator load sequencers automatically place vital safety-related equipment in service in the event that normal power is lost on an emergency bus. If a postulated accident were to occur concurrently with a loss of normal power, then the load sequencers would also automatically place the emergency core cooling system equipment inservice. The load sequencer timer/relays are used to distribute the loads being placed on the emergency electrical bus in six discrete timed steps over a 1-minute period. A total of eight timer/relays are installed in each emergency diesel generator load sequencer.

The original emergency diesel generator load sequencer timer/relays were Model ATC 305E electro-mechanical timer/relays manufactured by the Automatic Timer and Controls Company, Incorporated. During the first refueling outage, in 1989, difficulty was encountered with obtaining the necessary set-point repeatability with the electro-mechanical timer/relays. An engineering evaluation was completed to widen the set-point tolerances, thus allowing the Model 305E timer/relays to satisfy the acceptance criteria. Based on the performance of the timer/relays during the first outage, the decision was made to replace these timers during the second refueling outage.

During the second refueling outage, in November 1990, the original timer/relays were replaced with digital Model 365A microprocessor based timer/relays manufactured by the Automatic Timer and Controls Company, Incorporated. The timer/relays were procured as commercial grade components and dedicated by Wyle Laboratories for Class-1E service. To improve the timer/relay performance, the clock circuits were continuously energized on some of the timer/relays in accordance with vendor recommendations. The load sequencers functioned properly during surveillance testing conducted following this modification.

During the third refueling outage, in April 1992, routine surveillance tests identified three of the eight timer/relays in each sequencer train had failed. The failures were caused by the modification made to the timers that continuously energized the clock circuits. Continuously energizing the clock circuits caused overheating and the failure of a resistor in the timer/relays. The clock circuits had been continuously energized to improve the timer/relay set-point accuracy.

The timer/relay configuration was changed based on the vendor's recommendation, but verification of the adequacy of this recommendation was not thoroughly tested or analyzed. The cause of the failures was attributed to inadequate design control. The NRC conducted an enforcement conference regarding this issue and issued a Severity Level III violation and a Civil Penalty (NRC Inspection Reports 50-412/92-07 and 50-412/93-22). The failed timer/relays were replaced and the clock circuits were modified such that the timer/relays were only energized during sequencer operation. The load sequencers tested satisfactorily during the eighteen month surveillance tests conducted at the end of the outage.

2.2 Event Description

On November 4, 1993, during the performance of Operating Surveillance Test 36.3, "Emergency Diesel Generator Automatic Test," the Train-A, 2-1 emergency diesel generator (EDG) load sequencer failed to automatically load the emergency core cooling system equipment on the emergency electrical bus as designed. The routine surveillance test, which is conducted on an eighteen month interval, involved simulating a loss of normal power concurrent with a safety injection signal. During the test, the EDG started and reenergized the associated emergency bus; however, safety-related equipment did not automatically sequence onto the bus as expected. Approximately two minutes following the failure, the safety injection (SI) signal was manually reset. Resetting the safety injection signal caused the safety-related equipment to begin sequencing onto the emergency bus. The surveillance test was terminated and trouble-shooting activities were initiated.

Bench testing of the relays was not successful in identifying the cause of the failure. An evaluation of the sequencer logic circuit by the licensee's engineering staff identified two relays, one in the sequencer circuit and one in the solid state protection system, whose malfunction had the potential to cause the symptoms observed during the failed surveillance test. Both suspect relays were replaced, and diagnostic test equipment was installed to monitor the load sequencer operation. The operating surveillance test was successfully repeated on November 5, 1993. The diagnostic test equipment did not identify any component failures during this test.

On November 6, 1993, during the performance of Operating Surveillance Test 36.4, "Emergency Diesel Generator Automatic Test," the Train-B, 2-2 emergency diesel generator load sequencer failed to automatically load emergency core cooling system equipment on the bus as designed. Diagnostic test equipment had been installed on the load sequencer and provided pertinent information on the failure mode of the sequencer. The cause of the sequencer failure was identified as the safety injection reset relay (762EGSBA). This relay resets the load sequencer if a safety injection signal occurs during a loss of normal power event. A contact from this relay failed to open, which caused the load sequencer to "lock-up" and failed to automatically load equipment onto the emergency bus. Surveillance testing activities were suspended and an evaluation was initiated to determine the cause for the failure.

The operations staff notified the NRC of this failure of multiple trains of a safety system in accordance with 10 CFR 50.72(b)(2)(i) on November 6, 1993. In response, the NRC dispatched an Augmented Inspection Team on November 8, 1993, to review this event.

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2.3 Safety Significance

The failure of both emergency diesel generator load sequencers would prevent automatic initiation of the emergency core cooling systems in the event of an accident with a loss of normal power. The automatic initiation of the emergency core cooling systems would have functioned correctly for a postulated accident without the loss of normal power. The load sequencers would also have functioned correctly and loaded safety-related equipment in the event of a loss of normal power without an accident. In the event that the load sequencers were to malfunction during an accident with a loss of normal power, manual operator actions, in accordance with the emergency operating procedures, would be required to mitigate the consequences of the event. The manual actions include locally resetting the motor-control-centers. Resetting the motor-control-centers is required to restore service water to the emergency diesel generators, the high head safety injection pump coolers and to operate essential emergency core cooling system valves. For some postulated accidents, manual operator actions may not have been adequate to satisfy the design criteria for the emergency core cooling systems (10 CFR 50.46). The team concluded that the common cause failure of multiple trains of a safety system required to mitigate the consequences of an accident was a significant event.

At the time of the identification of this failure, Beaver Valley, Unit 2, was in cold shutdown and the automatic initiation of the emergency core system was not required. However, the susceptibility of the timer/relays to this failure mechanism appears to have existed since the microprocessor timer/relays were installed in 1990.

2.4 Load Sequencer Operation

The emergency diesel generator load sequencers automatically load safety-related equipment onto the 4 kV emergency busses following the detection of an undervoltage or degraded voltage conditions on the emergency busses and restoration of power. Additional emergency core cooling system equipment would be placed in service by the load sequencer if the loss of power were to occur concurrently with an accident. The safety-related equipment is loaded onto the diesel generators in six discrete, timed steps, over a 1-minute period, to prevent overloading the diesel generators. The function of the Train-A and Train-B load sequencers is identical. Therefore, only the Train-A sequencer operation will be described.

In the event that power is lost to an emergency bus, the associated emergency diesel generator will automatically start, and the diesel output circuit breaker will close to provide emergency power to the bus. The load sequencer blocks the automatic start function of equipment on the bus so that loads are place onto the diesel generator in a timed sequence. When the EDG output circuit breaker closes, the load sequencer master relay (3-EGSAAX) energizes (See Figure 1). The master relay starts seven timer/relays that start the timing of sequencer steps 2 through 7. The first step is when the EDG output breaker closes and the seventh step resets the sequencer after 1 minute.

When the timer/relays for steps 2, 3, 5 and 6 time-out, they energize an auxiliary relay, which initiates sequencing of specified loads onto the emergency bus. The step 4 timing relay is slightly different. When it times-out, it energizes a second timer/relay. This slave timer/relay energizes an auxiliary relay for 2 seconds, during which time an auxiliary feedwater pump and/or a quench spray pump may start. The auxiliary feedwater pump and the quench spray pump may also start any time after step 7. Step 7 is the final step in the sequencer, and it resets the load sequencer by deenergizing the master relay (3-EGSAAX).

The load sequencer is designed to reset following a safety injection (SI) or a Phase-B containment isolation (CIB) signal. The reset is required because the loads required during a SI or CIB are different than those required for a loss of normal power alone. Therefore, by resetting the load sequencer, the appropriate equipment is automatically placed in service. If the sequencer receives a reset signal after it has started running, loads already connected to the bus will remain operating. The reset of the load sequencer occurs when the SI reset timer/relay or the CIB reset timer/relay are energized. These relays are energized by engineered safety feature actuation system.

Each train of the load sequencer has eight Automatic Timer Controls, Model 365A microprocessor timer/relays. The microprocessor timer/relays are used for SI and CIB reset, sequence steps 3-6, sequencer reset, and the step 4 slave timer. The step 2 timer is a Model ITE-62K timer/relay manufactured by Asea Brown Boveri (ABB). The Model ITE-62K timer/relay is used for step 2 because of the additional accuracy needed in the timing of this step.

All of the auxiliary relays in the sequencer circuits are Model RXMH-2 electro-mechanical relays. The RXMH-2 relays were manufactured by Asea Brown Boveri.

A detailed description of the load sequencer operation is provided in Appendix B of this inspection report. A simplified logic diagram of the load sequencer circuit is provided in Figure 1.

2.5 Root Cause Failure Analysis

2.5.1 Sequencer Logic Failure

The configuration and operation of the Train-A and Train-B EDG load sequencers are identical; therefore, only the Train-A sequencer operation and failure will be described. The licensee installed diagnostic test equipment on the 2-2 emergency diesel generator load sequencer prior to the performance of the operating surveillance test. Following the failure of the load sequencer, the information collected from the diagnostic test equipment was analyzed to determine the cause.

The cause of the load sequencer failure was determined to be the malfunction of the safety injection microprocessor timer/relay (762-EGSAA) that is used for sequencer reset. Specifically, the microprocessor timer/relay time delay contact opened after a 1/2 second time delay and then inadvertently re-closed a very short time later (approximately 30 milliseconds). Closing of the 762-EGSAA time delay contact energized the 3-EGSAAX4 relay, which "locked-out" (deenergized) the load sequencer master relay and prevented further load sequencer operation.

The diagnostic test equipment also identified that a large negative voltage spike resulted from deenergizing the auxiliary relay (3-EGSAAX4) coil. The auxiliary relay coil (3-EGSAAX4) deenergized when the microprocessor timer/relay (762-EGSAA) time delay contact (762-TDO) opened. The spike was generated by the sudden change in current in the auxiliary relay coil (inductor). The rise and fall times of the voltage spike were very fast and the amplitude of the voltage spike was in excess of 1100 volts at the 762-TDO contact. The voltage spike was transmitted back into the input, power line, and electronics of the microprocessor timer/relay (762-EGSAA) by the arc shower process across the 762-TDO contact. The resulting electronic interference caused the microprocessor to malfunction and reclosed the 762-TDO contact.

2.5.2 Microprocessor Timer/Relay Failure

The licensee conducted a series of bench tests of the microprocessor timer/relays to obtain additional information regarding the failure. The test setup used both a microprocessor timer/relay and an auxiliary relay. These relays were tested in a circuit configuration identical to the in-plant configuration. The results of these bench tests indicated an intermittent failure mode of the microprocessor timer/relays.

The 2-1 load sequencer was temporarily modified to allow the performance of *in situ* testing of the sequencer without starting the safety-related loads. The results of this *in situ* testing indicated an intermittent failure mode of the microprocessor timer/relay (762-EGSAA). These *in situ* tests were instrumented to provide information regarding the magnitude and location of the voltage spikes that occurred during sequencer operation.

The licensee also conducted failure analysis tests internal to the microprocessor timer/relay. The tests concluded that the failure was due to microprocessor malfunction. The cause of microprocessor malfunction was attributed to the negative voltage spikes which were generated when the internal relay deenergized the auxiliary relay coil. The internal relay and contacts (762-TDO) were mounted on the same printed circuit card as the electronic parts and the microprocessor. Consequently, the negative voltage spikes affected the microprocessor and electronic circuitry through an indeterminate transient process involving the internal relay. The exact transient mechanism was not determined at a level below the circuit board indications. The timer/relay vendor engineer stated that symptoms of a microprocessor failure were that the time display malfunctions and the internal timed relay deenergizes, thus causing the normally closed internal timed relay contact to close. Since the normally closed contact were used in the auxiliary relay circuit, the result was that the auxiliary relay would not be deenergized as required at the end of the microprocessor controlled time delay. This description matched the failure analysis indications. The vendor engineer also stated that the probable cause was due to the inductive discharge of energy across the contacts of the internal relay. This would cause transient arcing and could generate electronic interference internal to the timer/relay, which could cause the microprocessor to malfunction. The inductive energy discharge transient across the contacts is called arc shower and is always a direct consequence of interrupting an inductive current. The licensee plans to send a microprocessor timer/relay to the vendor for additional failure analysis of the electronic circuitry.

Diode suppression of the voltage spikes at the auxiliary relay removed the cause of the arc shower effect and allowed the microprocessor timer/relay to function properly. The effectiveness of diodes in suppressing the voltage spikes created during the deenergization of the auxiliary relays was determined by testing. The microprocessor timer/relay and auxiliary relay were bench tested in the in-plant configuration with the addition of a diode installed in parallel with the coil of the auxiliary relay. The results of these tests showed no failures after approximately 80 operations and indicated a significant reduction in the magnitude of the negative voltage spikes.

The team noted that test results were frequently not well documented. However, the root cause evaluation described and summarized all the testing in a comprehensive, logical manner.

2.5.3 Engineering Process and Root Cause

To determine the root cause of the failure of the emergency diesel generator (EDG) load sequencer the team evaluated the load sequencer circuit design, the failed microprocessor timer/relay (762-EGSAA), and the engineering process for design control.

The licensee's engineering personnel did not suspect that voltage spikes, that normally result from deenergizing auxiliary relays, would present a problem in this application of the microprocessor timer/relay. This was based on their interpretation of the vendor's data sheet, which did not contain any information or precautions that indicated susceptibility of the microprocessor timer/relay to voltage spikes associated with deenergizing auxiliary relays. The licensee did not conduct any confirmatory testing, analysis, or written justification that independently verified the vendor's implied statement concerning the non-susceptibility of the microprocessor timer/relay to voltage disturbances. The team noted that the vendor's data sheet did not discuss noise suppression when using the contacts to control direct current (dc) powered relays. But there were precautions stated for the auxiliary relay. In the auxiliary relay data sheet, the protection of electronic circuits against the auxiliary relay coil inductive voltage type transients was covered along with details of diode suppression techniques.

The modification process and the 10 CFR 50.59 safety evaluation for the modification that installed the microprocessor timer/relays did not list or evaluate inductive spiking as a possible failure mechanism for the microprocessor timer/relays, even though the possibility of spiking existed. Since no suppression techniques were included in the modification, voltage spikes would, therefore, be present and should have been evaluated. The previous failure of the load sequencer in 1992 was attributed to weak design control. At this time, an opportunity was missed to conduct additional design reviews of this modification to determine if other design control deficiencies existed.

The team reviewed the post modification test data from the initial design change and determined that the data did not provide information on load sequencer voltage spikes. The licensee's root cause determination concluded that a more rigorous post modification test may have identified this failure mode.

The team concluded that the effects of the inductive voltage transient which caused arc showering, due to the interruption of an inductive current, were inadequately evaluated in the design process. This resulted in a sequencer design with an inherent failure mechanism that had an extremely high potential for the introduction of a common cause failure.

Therefore, the team attributes the root cause of this event to an inadequate engineering evaluation of the susceptibility of the microprocessor relay/timer to the installed electromagnetic interference (EMI) service conditions. The evaluation did not encompass the EMI sources (such as fast transient voltage spikes/arc shower in this case) or the effect of those EMI sources on the replacement component.

2.6 Corrective Actions

2.6.1 Suppression Diode Installation

Minor design change package (MDCP) number 2057 was developed to prevent the malfunction of microprocessor timer/relays 162-EGSAAX1, 762-EGSAA, 862-EGSAA, 162-EGSBAX1, 762-EGSBA and 862-EGSBA, while the microprocessor timer/relays are deenergizing their respective auxiliary relays. This was accomplished by the installation of inductive voltage transient suppressors across nine auxiliary relay coils in each sequencer train. The sequencer timer/relays and auxiliary relays are located in power panel PNL*SEQ244 for Train-A and in power panel PNL*SEQ254 for Train-B. The applicable portions of the schematics showing the pre-modification and post-modification configurations of the EDG loading sequencer are provided in Figures 1 and 2 of this inspection report, respectively.

The suppressors consisted of diodes which were installed in parallel with the auxiliary relay coils to suppress the voltage spikes created when the relay coils are deenergized. The suppressor type selected was an ABB terminal base mounted, RTXE with the type 2 assembly. These diodes were designed for use with the ABB RXMH-2 type coil relays and other ABB type relays. The purpose of these diodes, as explicitly stated in the published ABB relay data sheets, was "to obtain a dropout delay for dc relays or to protect electronic circuits against transients."

The 10 CFR 50.59 safety evaluation worksheet associated with the modification was reviewed. The safety evaluation identified that the only parameters affected by this change were the voltage and the timing associated with the operation of the sequencer relays. The safety evaluation stated that the addition of a diode to the coil of the ABB RXMH-2 relay delays the dropout time by approximately 20 milliseconds. The safety evaluation concluded that this 20 millisecond delay was not significant compared to the required accuracy of the sequencer, which is on the order of 200 milliseconds. However, the conclusion that the 20 millisecond time delay would not affect sequencer operation was incorrect. A problem with the auxiliary feedwater (AFW) pump start sequence was identified during the performance of the functional test, 2OST-36.3. With the exception of this relay timing problem, the team determined that the MDCP and associated 10 CFR 50.59 evaluation were adequate.

The installation and initial testing of the suppressors for the Train-A load sequencer was completed on November 14, 1993, with the final post-modification testing completed on November 16, 1993. The Train-B diode suppressors were installed and subsequently tested on November 17, 1993. In addition to the installation of the suppressors, microprocessor timer/relays 762-EGSAAX, 862-EGSAAX, and the 862-EGSBAX were replaced.

2.6.2 Auxiliary Feedwater Pump Logic Change

During the performance of the diesel generator 2-1 functional test 2OST-36.3, "Emergency Diesel Generator Automatic Tests," the auxiliary motor driven feedwater (AFW) pump inadvertently started immediately following the closure of the EDG output circuit breaker, rather than at load sequencer step 4. Load sequencer Step 4 equipment is supposed to load 15 to 17 seconds after the emergency diesel output circuit breaker closes. The licensee determined that the cause of the inadvertent start was a delay in the deenergization of auxiliary relay 162-EGSAAX, at the beginning of the loading sequence. The delay in the deenergization of the 162-EGSAAX relay was introduced by the addition of diode suppressors and was not identified during the development of the modification. The AFW pump starting logic is identical for Train-A and Train-B; therefore, only the Train-A starting logic will be described.

AFW Pump Starting Logic Operation

The motor driven auxiliary feedwater pump starting logic consisted of three contacts in series that were all required to close to start the AFW pump. (Not to be confused with the simplified schematic in Figures 1 and 2.) These contacts were closed when voltage was available on the emergency bus, when the load sequencer auxiliary relay 162-EGSAAX was energized (sequencer step 4), and when a safety injection signal was present. The load sequencer relay 162-EGSAAX was normally energized and deenergized when the EDG output circuit breaker closed. This logic was designed to deenergize the 162-EGSAAX relay before the voltage sensing relays on the emergency bus picked-up following power restoration by the EDG. Deenergizing the 162-EGSAAX relay opened a contact in the AFW pump starting logic that prevented starting the AFW pump prior to sequencer step 4. At sequencer step 4, the 162-EGSAAX relay energized and started the AFW pump.

AFW Pump Starting Logic Failure

After the failure of the functional test, the licensee reviewed the AFW pump starting circuit to determine why the AFW pump inadvertently started at sequencer step 1 rather than at step 4. During step 1 of the loading sequence, the safety injection (SI) contact in the AFW pump starting circuit was closed. The two additional contacts in the starting circuit were the 162-EGSAAX contact from the sequencer and the voltage available on the emergency bus contact from the bus voltage sensing relays. To prevent premature starting of the AFW pump, the 162-EGSAAX relay must deenergize prior to the voltage available on the bus sensing relays pick-up. This developed a race between the two relays. The installation of the suppressor diodes around the 162-EGSAAX relay caused a delay in the drop-out time of the 162-EGSAAX relay. This delay allowed the emergency bus voltage relay contacts to close prior to the opening of the 162-EGSAAX contacts, thus starting the AFW pump.

The modification which installed the diode suppressors did not assess the effect of the delay in auxiliary relay drop-out time on the sequencer operation. The associated safety evaluation identified that the expected delay in relay drop-out was approximately 20 milliseconds. The safety evaluation correctly stated that this would not adversely affect the overall delay time in loading safety-related equipment. However, the safety evaluation did not document the effect that this would have on the AFW pump start circuit. In addition the functional test measured the actual delay in relay drop-out time to be approximately 70 milliseconds.

Corrective Actions

In response to this failure, the licensee performed a detailed review of the sequencer circuit and verified that no other potential start logic problems existed. In order to correct the failure associated with the AFW pump starting circuit, the licensee initiated an Engineering Change Notice (ECN) to modify the AFW pump starting circuitry such that the 162-EGSAAX relay would not be energized prior to load sequence step 4. The design change prevents the possibility of having the three AFW pump starting circuit contacts closed prior to sequencer step 4. The 162-EGSAAX relay would be energized for 2 seconds at step 4 of the load sequence. An additional change to the AFW pump start circuit was required to provide a second AFW pump a start signal after the final sequencer step.

Conclusion

The implications of the installation of the diode suppressors on the relay timing were not thoroughly evaluated. Following the installation of the suppressors, the delay in slave relay drop-out time caused the AFW pump to start at the wrong sequence step. An additional design change was required to correct this problem. The team concluded that the actions taken by the licensee to correct this problem were acceptable. However, the team considered the inadequate evaluation of the suppressor installation on relay timing as another example of a weak design control process.

2.6.3 Post Modification Testing

After the installation of the suppressors, the modification design change package required the performance of sequencer testing to verify that the microprocessor timer/relays and the auxiliary relays were functioning properly. The modification design change package required that each sequencer train be tested a total of 30 times. Fifteen cycles were to be initiated by loss of normal power with an SI signal. The remaining fifteen cycles were to be initiated by loss of normal power with a CIB signal. The first and last run for each set of fifteen cycles were to be instrumented to allow for engineering review of the associated traces.

In addition to the testing required for the completion of the modification, other *in situ* tests were performed to verify that the installation of the of the suppression diodes allowed for proper sequencer operation. In total, approximately 200 *in situ* tests were performed with no failures. Whereas, *in situ* testing performed prior to the installation of the suppressors indicated a failure rate of approximately 35%. These post-modification tests verified the operation of the sequencer for loss of offsite power conditions, separately, and with a SI signal or a CIB signal. Approximately 20% of these tests were instrumented to verify that the voltage spikes were adequately suppressed, and to verify that the suppression diodes showed no signs of degradation. The licensee also performed the Operating Surveillance Tests 2OST-36.3 and 2OST-36.4, "Emergency Diesel Generator Automatic Tests," prior to declaring the sequencers operable. The team observed portions of these tests and determined that they were acceptable to demonstrate system operability.

2.7 Equipment Qualification

ATC Timer Relay Dedication

The Beaver Valley Unit 2 Updated Final Safety Analysis Report, Table 8.1-1, lists the Institute of Electrical and Electronic Engineers Standard (IEEE) 323-1974, "Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," as acceptance criteria for Class 1E components. This standard was used as guidance for the dedication of the ATC Model 365A microprocessor timer/relays.

The microprocessor timer/relays were procured as commercial grade items in the spring of 1990 and installed in the load sequencers in the fall of 1990. The dedication of the timer/relays as Class 1E components was controlled through the licensee's engineering design change process rather than through the commercial dedication program. The design change package stated that the following actions were necessary to dedicate the relays:

- A review and evaluation by a third party of the Class 1E environmental qualification of the microprocessor timer/relays. The review and evaluation was to be governed by IEEE 323-1974 (as interpreted by NUREG-0588, Rev. 1) and the seismic qualification requirements of IEEE 344-1975. The environmental qualification parameters specified in the procurement document were: temperature, pressure, humidity, cumulative radiation dose, aging, and seismic forces.

- An initial calibration and checkout of the relays prior to installation.

- A continuity test of the relay circuits to ensure that they were wired properly.

- A functional test of each sequencer circuit.

The third party review and evaluation was complete by Wyle Laboratories. The review was thorough, and provided adequate justification for qualification of the relays as specified in the procurement specification. However, the following deficiencies were noted in the licensee's overall qualification package for the microprocessor timer/relays (the combination of Wyle's testing and the onsite testing) when compared to the requirements of IEEE 323-1974:

- Electromagnetic interference (EMI) was not considered as part of the relay qualification. The term EMI encompasses both external (or radiated) EMI and circuit induced EMI. Section 6.2(2) of IEEE 323-1974 states that Class 1E qualification shall include electromagnetic interference.

- IEEE 323 requires specification of the equipment operating environment. The licensee indicated weakness in this area as illustrated by the following:

  (1) The equipment performance specifications did not define the transient range of voltage under which the relays were expected to operate.

  (2) The circuit configuration specified in the procurement specification was not the actual configuration used for all the relays. Some of the installed relays were wired with their clock power supplies continuously energized. The configuration qualified by Wyle had the relays energized only when the sequencer was called on to operate. This eventually led to failure of the relays as discovered in the spring of 1992. This deficiency was covered by Enforcement Action 92-085.

- The qualification documentation was not organized in a auditable form as specified in Section 8 of IEEE 323-1974. The documentation supplied by Wyle was thorough; however, the post-modification test results were not incorporated in the qualification documentation.

Following the sequencer failures on November 4 and 6, 1993, the licensee modified the sequencer design and performed supplemental testing to provide reasonable assurance that the ATC timer/relays installed in the load sequencers would operate as designed. They did not, however, develop an auditable qualification package for the relays. Additionally, no documentation was developed to indicate the status of the ATC timer/relays in the warehouse. The licensee's spare microprocessor timer/relays underwent third party review by Farwell & Hendricks, Inc. Since the spare microprocessor relays do not have auditable qualification documentation, and have not received rigorous testing like the installed relays, their Class 1E qualification requires documentation.

Suppression Diode Dedication

The team reviewed commercial grade evaluation, D-905786, for the suppression diodes. The critical characteristics defined by the licensee were appropriate for the intended application of the suppression diodes. Additionally, the commercial grade evaluation contained appropriate calculations to support the selection of the critical characteristics.

2.8 Generic Implications

Beaver Valley Specific

In addition to the microprocessor timer/relays installed in the sequencers, four additional ATC-365A microprocessor timer/relays are installed in the recirculation spray (RSS) pump starting circuits. These timer/relays start the RSS pumps 628 seconds after the receipt of a containment isolation phase-B (CIB) signal. A failure of the "D" RSS pump occurred during the performance of surveillance testing during the week of November 1, 1993. The timer/relay started the "D" RSS pump at the time the CIB signal was simulated and did not delay the pump start for 628 seconds. The timer/relay was removed from the circuit for further investigation and bench testing. During bench testing, 125 Vdc was inadvertently applied directly to the timer/relay without a voltage dropping resistor. The voltage dropping resistor was required to reduce the supply voltage to the timer/relay from the 125 Vdc to the design voltage of 24 Vdc. As a result of this error, the timer/relay was destroyed and was not available for further testing. A new timer/relay was installed in the RSS pump starting circuit and a functional test was successfully performed. The team considered the licensee's inadvertent damaging of the failed RSS pump microprocessor timer/relay as an example of weak troubleshooting practices.

Functional test 2BVT1.13.5, "Recirculation Spray Pump Test," was performed, with diagnostic test equipment installed, to determine if voltage spikes were affecting the performance of the RSS pump microprocessor timer/relays. The test identified one negative voltage spike at the microprocessor timer/relay input from the RSS pump breaker trip coil. During accident conditions, the RSS pump would not be tripped until the CIB signal had been reset. When the CIB signal is reset, the RSS pump microprocessor timer/relays are isolated from the RSS pump starting circuit. Therefore, any RSS pump breaker trip coil induced voltage spikes would not adversely affect the microprocessor timer/relay ability to start the RSS pump.

In order to determine if any other solid-state electronic relays had been installed at the Beaver Valley Power Station, the licensee reviewed the category one design change packages (DCPs) implemented over the past five years. This review identified four DCPs that installed solid-state electronic relays. The relays installed by these DCPs were determined to have adequate documentation regarding transient immunity that enveloped the expected transients conditions, or had been appropriately tested for surge withstand capability, fast transient and EMI susceptibility. Therefore, these relays should be suitable for their installed application.

Industry Generic Implications

The team determined that the load sequencer failures at Beaver Valley have generic implications. The generic issue is that licensees must conduct a thorough design review when replacing discrete component electrical devices with digital, microprocessor based electronic devices. Specifically, licensees need to conduct a detailed case-by-case design review to assure that the digital, microprocessor based replacement equipment is compatable for the specific application. This review is necessary since solid state electronic equipment is generally more susceptible to damage from system disturbances than their electromechanical predecessors, particularly with respect to electromagnetic interference and other power supply instabilities.

2.9 Commitments

The first three commitments listed below were provided in the licensee's letter to the NRC, dated November 18, 1993. In addition, the licensee staff stated that a review would be conducted to evaluate the feasibility of additional sequencer testing, and the commercial grade dedication package documentation for microprocessor timer/relays would be upgraded. It is the team's understanding that the licensee plans to do the following:

1. An ATC timer/relay will be sent to the manufacturer for failure analysis.

2. An evaluation of the licensee's capability to identify and specify modification tests which detect functional degradation of modified equipment will be conducted. Until completion of the evaluation, Engineering Assurance and System Engineers will review modification packages prior to installation and will concur with the modification testing requirements.

3. Engineering guidelines will be developed which address engineering requirements for the application of digital solid state components as replacements for non-digital components.

4. A review will be conducted to determine if additional testing of the emergency diesel generator sequencers is feasible and appropriate.

5. The qualification package for the ATC timer/relays will be upgraded to satisfy the IEEE-323-1974 standards. Documentation of the EMI type testing conducted on the ATC relay will be included in the commercial grade qualification package.

2.10 Conclusions

The modification which installed the Model 365A ATC microprocessor timer/relays was inadequate. The design control for the selection and review for suitability of the ATC timer/relays for this application was not adequate. The modification design inputs should have identified the potential for voltage spiking by the auxiliary relays. This design input should then have been translated into the equipment purchase specification and the dedication testing specification.

The implications of the installation of the diodes on relay timing was not thoroughly evaluated. The delay in the slave relay drop-out caused an auxiliary feedwater pump to start at the wrong sequence step following the installation of the diodes. Further design changes were required to correct this problem. The team concluded that the actions taken to correct this problem were acceptable.

The installation of the diodes to suppress voltage spikes was an acceptable corrective action. The team independently verified the test results and concluded that this modification makes the emergency diesel generator load sequencer operable.

Test control and trouble-shooting of the failed relays was weak. For example, the failed relay from the recirculation spray pump was inadvertently destroyed, preventing further investigative testing.

The corrective actions taken in response to the April 1992 clock failures were adequate. However, an opportunity to further evaluate the selection of the microprocessor timer/relays for this service application was missed at this time. The team concluded that the failure mechanism and corrective actions taken in response to the clock failures were independent of the current timer/relay failures.

The qualification documentation for the ATC 365A timer/relays was incomplete. The documentation did not address electromagnetic interference issues and was not put together in an organized and auditable format as specified in IEEE-323-1974.

3.0 EXIT MEETING

The team met with those denoted in Appendix A, on December 2, 1993, to discuss the preliminary inspection findings which are detailed in this report. The exit meeting was open for public observation and the NRC answered public questions following the exit meeting. The slides used at the exit meeting are provided as Attachment 2 of this inspection report.

APPENDIX A

Persons Contacted

Duquesne Light Company

* P. Bienick	Project Engineer
* L. Freeland	General Mgr. Nuclear Operations
* K. Grada	Mgr. Quality Services Unit
* K. Halliday	Director, Electrical Engineering
* F. Lipchick	Sr. Licensing Supr.
* D. McBride	System Engineer
* D. McLain	Mgr. Maintenance Engineering and Assessment
* T. Noonan	Gen. Mgr., Nuclear Engineering and Safety
* D. O'Neil	Gen. Mgr. Public Affairs
* J. Sasala	Director, Nuclear Communication
* R. Scheib	ANSS Unit 2
* J. Sieber	Sr. Vice President - Nuclear Power Division
* M. Siegel	Mgr. Nuclear Engineering Department
* G. Storolis	NSS Unit 2
* D. Szucs	Sr. Engineer, Nuclear Safety
* G. Thomas	Division Vice President - Nuclear Service
* N. Tonet	Mgr. Nuclear Safety
* G. Zupic	Supr. Reactor Engineering

U. S. Nuclear Regulatory Commission

* G. Edison	Project Manager, NRR
* C. Miller	Deputy Division Director, DRS
* L. Rossbach	Sr. Resident Inspector - Beaver Valley

Other

* G. Morris	Video Photographer
* J. Musala	Reporter
* B. Shaw	DLC-retired
* R. Barkanic	Nuclear Engineer, Pa. State DER/BRP

Asterisk (*) denotes those present at the exit meeting conducted on December 2, 1993. The persons contacted list is not a comprehensive list of every individual contacted but provides the principal staff associated with this event.

APPENDIX E

SEQUENCER OPERATION

The following provides a description of the function of the emergency diesel generator load sequencer operation. The Train-A and Train-B load sequencer operations are identical; therefore, only the Train-A sequencer operation will be described. A simplified logic diagram of this circuit is provided in Figure 1 of this inspection report.

Sequencer Operation

1. A loss of offsite power will result in the opening of the normal supply circuit breakers to the emergency bus and the automatic start of the associated emergency diesel generator. The opening of the normal supply circuit breaker to the emergency bus will cause the 52S-ENSAC contact to close.

2. Following the EDG attaining rated speed and voltage, the EDG output circuit breaker closes and contact 52S-ECPAA closes. This energizes master relay, 3-EGSAAX, because the 69-EGSAA and the 3-EGSAAX4 contacts are normally closed. Once the master relay is energized, its associated contacts in the circuits for the slave timer/relays are closed allowing the loads to sequence on in the proper order.

3. When an SI signal is present, contact SIS-K610XA would close.

4. The closing of contact SIS-K610XA provides power to the microprocessor timer/relay 762-EGSAA.

5. When microprocessor timer/relay 762-EGSAA energizes, its timer operation is started, and its normally open 762-INST contact closes.

6. At the closing of contact 762-INST, the SI/CIB reset relay, 3-EGSAAX4, energizes.

7. When relay 3-EGSAAX4 energizes, its normally closed contact in the master relay circuit opens, deenergizing the master relay and consequently all of its slave timer-relays.

8. At 0.5 seconds after energization of the 762-EGSAAX microprocessor timer/relay (step 3 above), its normally closed 762-TDO contact opens, deenergizing the SI/CIB reset relay, 3-EGSAAX4. The 762-TDO contact stays open until the 762-EGSAAX microprocessor timer/relay is reset (i.e. deenergized).

9. When the 3-EGSAAX4 relay deenergizes, its normally closed contact, which was opened as described in step 5 above, recloses and reenergizes the master relay, 3-EGSAAX, and all its slave timer/relays. Energizing these slave timer/relays allows the safety equipment to load in the proper sequence.

ATTACHMENT 1

AUGMENTED INSPECTION TEAM CHARTER

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

Docket No. 50-412

NOV 9 1993

MEMORANDUM FOR: Marvin W. Hodges, Director, Division of Reactor Safety

FROM: Thomas T. Martin, Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER FOR REVIEW OF COMMON MODE FAILURE OF THE EMERGENCY DIESEL GENERATOR LOAD SEQUENCERS AT BEAVER VALLEY UNIT 2

On November 4, 1993, during the load sequencing test of the 2-1 emergency diesel generator (EDG), the load sequencer malfunctioned in such a manner as to prevent automatic loading of the EDG. On November 6, 1993, a load sequencer malfunctioned on the 2-2 EDG. Subsequent testing revealed that a common-mode problem exists that may have prevented either EDG from loading automatically. In order to assess the safety significance of the issue, I have determined that an Augmented Inspection Team (AIT) should be initiated to review the causes and safety implications associated with these malfunctions.

The Division of Reactor Safety (DRS) is assigned the responsibility for the overall conduct of this Augmented Inspection. Jim Trapp, Team Leader, DRS, is appointed as Augmented Inspection Team Leader. Other AIT members are identified in Enclosure 2. The Division of Reactor Projects (DRP) is assigned the responsibility for resident and clerical support, as necessary; and the coordination with other NRC offices, as appropriate. Further, the Division of Reactor Safety, in coordination with DRP is responsible for the timely issuance of the inspection report, the identification and processing of potentially generic issues, and the identification and completion of any enforcement action warranted as a result of the team's review.

Enclosure 1 represents the charter for the Augmented Inspection Team and details the scope of the inspection. The inspection shall be conducted in accordance with NRC Management Directive (MD) 8.3, NRC Inspection Manual 0325, Inspection Procedure 93800, Regional Office Instruction 1010.1, and this memorandum.

William F. Kane /for
Thomas T. Martin
Regional Administrator

Enclosures:
1. Augmented Inspection Team Charter
2. Team Membership

When the timer/relays for steps 2, 3, 5 and 6 time-out, they energize an auxiliary relay, which initiates sequencing of specified loads onto the emergency bus. The step 4 timing relay is slightly different. When it times-out, it energizes a second timer/relay. This slave timer/relay energizes an auxiliary relay for 2 seconds, during which time an auxiliary feedwater pump and/or a quench spray pump may start. The auxiliary feedwater pump and the quench spray pump may also start any time after step 7. Step 7 is the final step in the sequencer, and it resets the load sequencer by deenergizing the master relay (3-EGSAAX).

The load sequencer is designed to reset following a safety injection (SI) or a Phase-B containment isolation (CIB) signal. The reset is required because the loads required during a SI or CIB are different than those required for a loss of normal power alone. Therefore, by resetting the load sequencer, the appropriate equipment is automatically placed in service. If the sequencer receives a reset signal after it has started running, loads already connected to the bus will remain operating. The reset of the load sequencer occurs when the SI reset timer/relay or the CIB reset timer/relay are energized. These relays are energized by engineered safety feature actuation system.

Each train of the load sequencer has eight Automatic Timer Controls, Model 365A microprocessor timer/relays. The microprocessor timer/relays are used for SI and CIB reset, sequence steps 3-6, sequencer reset, and the step 4 slave timer. The step 2 timer is a Model ITE-62K timer/relay manufactured by Asea Brown Boveri (ABB). The Model ITE-62K timer/relay is used for step 2 because of the additional accuracy needed in the timing of this step.

All of the auxiliary relays in the sequencer circuits are Model RXMH-2 electro-mechanical relays. The RXMH-2 relays were manufactured by Asea Brown Boveri.

A detailed description of the load sequencer operation is provided in Appendix B of this inspection report. A simplified logic diagram of the load sequencer circuit is provided in Figure 1.

2.5 Root Cause Failure Analysis

2.5.1 Sequencer Logic Failure

The configuration and operation of the Train-A and Train-B EDG load sequencers are identical; therefore, only the Train-A sequencer operation and failure will be described. The licensee installed diagnostic test equipment on the 2-2 emergency diesel generator load sequencer prior to the performance of the operating surveillance test. Following the failure of the load sequencer, the information collected from the diagnostic test equipment was analyzed to determine the cause.

The cause of the load sequencer failure was determined to be the malfunction of the safety injection microprocessor timer/relay (762-EGSAA) that is used for sequencer reset. Specifically, the microprocessor timer/relay time delay contact opened after a 1/2 second time delay and then inadvertently re-closed a very short time later (approximately 30 milliseconds). Closing of the 762-EGSAA time delay contact energized the 3-EGSAAX4 relay, which "locked-out" (deenergized) the load sequencer master relay and prevented further load sequencer operation.

The diagnostic test equipment also identified that a large negative voltage spike resulted from deenergizing the auxiliary relay (3-EGSAAX4) coil. The auxiliary relay coil (3-EGSAAX4) deenergized when the microprocessor timer/relay (762-EGSAA) time delay contact (762-TDO) opened. The spike was generated by the sudden change in current in the auxiliary relay coil (inductor). The rise and fall times of the voltage spike were very fast and the amplitude of the voltage spike was in excess of 1100 volts at the 762-TDO contact. The voltage spike was transmitted back into the input, power line, and electronics of the microprocessor timer/relay (762-EGSAA) by the arc shower process across the 762-TDO contact. The resulting electronic interference caused the microprocessor to malfunction and reclosed the 762-TDO contact.

2.5.2 Microprocessor Timer/Relay Failure

The licensee conducted a series of bench tests of the microprocessor timer/relays to obtain additional information regarding the failure. The test setup used both a microprocessor timer/relay and an auxiliary relay. These relays were tested in a circuit configuration identical to the in-plant configuration. The results of these bench tests indicated an intermittent failure mode of the microprocessor timer/relays.

The 2-1 load sequencer was temporarily modified to allow the performance of *in situ* testing of the sequencer without starting the safety-related loads. The results of this *in situ* testing indicated an intermittent failure mode of the microprocessor timer/relay (762-EGSAA). These *in situ* tests were instrumented to provide information regarding the magnitude and location of the voltage spikes that occurred during sequencer operation.

The licensee also conducted failure analysis tests internal to the microprocessor timer/relay. The tests concluded that the failure was due to microprocessor malfunction. The cause of microprocessor malfunction was attributed to the negative voltage spikes which were generated when the internal relay deenergized the auxiliary relay coil. The internal relay and contacts (762-TDO) were mounted on the same printed circuit card as the electronic parts and the microprocessor. Consequently, the negative voltage spikes affected the microprocessor and electronic circuitry through an indeterminate transient process involving the internal relay. The exact transient mechanism was not determined at a level below the circuit board indications. The timer/relay vendor engineer stated that symptoms of a microprocessor failure were that the time display malfunctions and the internal timed relay deenergizes, thus causing the normally closed internal timed relay contact to close. Since the normally closed contact were used in the auxiliary relay circuit, the result was that the auxiliary relay would not be deenergized as required at the end of the microprocessor controlled time delay. This description matched the failure analysis indications. The vendor engineer also stated that the probable cause was due to the inductive discharge of energy across the contacts of the internal relay. This would cause transient arcing and could generate electronic interference internal to the timer/relay, which could cause the microprocessor to malfunction. The inductive energy discharge transient across the contacts is called arc shower and is always a direct consequence of interrupting an inductive current. The licensee plans to send a microprocessor timer/relay to the vendor for additional failure analysis of the electronic circuitry.

Diode suppression of the voltage spikes at the auxiliary relay removed the cause of the arc shower effect and allowed the microprocessor timer/relay to function properly. The effectiveness of diodes in suppressing the voltage spikes created during the deenergization of the auxiliary relays was determined by testing. The microprocessor timer/relay and auxiliary relay were bench tested in the in-plant configuration with the addition of a diode installed in parallel with the coil of the auxiliary relay. The results of these tests showed no failures after approximately 80 operations and indicated a significant reduction in the magnitude of the negative voltage spikes.

The team noted that test results were frequently not well documented. However, the root cause evaluation described and summarized all the testing in a comprehensive, logical manner.

2.5.3 Engineering Process and Root Cause

To determine the root cause of the failure of the emergency diesel generator (EDG) load sequencer the team evaluated the load sequencer circuit design, the failed microprocessor timer/relay (762-EGSAA), and the engineering process for design control.

The licensee's engineering personnel did not suspect that voltage spikes, that normally result from deenergizing auxiliary relays, would present a problem in this application of the microprocessor timer/relay. This was based on their interpretation of the vendor's data sheet, which did not contain any information or precautions that indicated susceptibility of the microprocessor timer/relay to voltage spikes associated with deenergizing auxiliary relays. The licensee did not conduct any confirmatory testing, analysis, or written justification that independently verified the vendor's implied statement concerning the non-susceptibility of the microprocessor timer/relay to voltage disturbances. The team noted that the vendor's data sheet did not discuss noise suppression when using the contacts to control direct current (dc) powered relays. But there were precautions stated for the auxiliary relay. In the auxiliary relay data sheet, the protection of electronic circuits against the auxiliary relay coil inductive voltage type transients was covered along with details of diode suppression techniques.

The modification process and the 10 CFR 50.59 safety evaluation for the modification that installed the microprocessor timer/relays did not list or evaluate inductive spiking as a possible failure mechanism for the microprocessor timer/relays, even though the possibility of spiking existed. Since no suppression techniques were included in the modification, voltage spikes would, therefore, be present and should have been evaluated. The previous failure of the load sequencer in 1992 was attributed to weak design control. At this time, an opportunity was missed to conduct additional design reviews of this modification to determine if other design control deficiencies existed.

The team reviewed the post modification test data from the initial design change and determined that the data did not provide information on load sequencer voltage spikes. The licensee's root cause determination concluded that a more rigorous post modification test may have identified this failure mode.

The team concluded that the effects of the inductive voltage transient which caused arc showering, due to the interruption of an inductive current, were inadequately evaluated in the design process. This resulted in a sequencer design with an inherent failure mechanism that had an extremely high potential for the introduction of a common cause failure.

Therefore, the team attributes the root cause of this event to an inadequate engineering evaluation of the susceptibility of the microprocessor relay/timer to the installed electromagnetic interference (EMI) service conditions. The evaluation did not encompass the EMI sources (such as fast transient voltage spikes/arc shower in this case) or the effect of those EMI sources on the replacement component.

2.6 Corrective Actions

2.6.1 Suppression Diode Installation

Minor design change package (MDCP) number 2057 was developed to prevent the malfunction of microprocessor timer/relays 162-EGSAAX1, 762-EGSAA, 862-EGSAA, 162-EGSBAX1, 762-EGSBA and 862-EGSBA, while the microprocessor timer/relays are deenergizing their respective auxiliary relays. This was accomplished by the installation of inductive voltage transient suppressors across nine auxiliary relay coils in each sequencer train. The sequencer timer/relays and auxiliary relays are located in power panel PNL*SEQ244 (for Train-A and in power panel PNL*SEQ254 for Train-B. The applicable portions of the schematics showing the pre-modification and post-modification configurations of the EDG loading sequencer are provided in Figures 1 and 2 of this inspection report, respectively.

The suppressors consisted of diodes which were installed in parallel with the auxiliary relay coils to suppress the voltage spikes created when the relay coils are deenergized. The suppressor type selected was an ABB terminal base mounted, RTXE with the type 2 assembly. These diodes were designed for use with the ABB RXMH-2 type coil relays and other ABB type relays. The purpose of these diodes, as explicitly stated in the published ABB relay data sheets, was "to obtain a dropout delay for dc relays or to protect electronic circuits against transients."

The 10 CFR 50.59 safety evaluation worksheet associated with the modification was reviewed. The safety evaluation identified that the only parameters affected by this change were the voltage and the timing associated with the operation of the sequencer relays. The safety evaluation stated that the addition of a diode to the coil of the ABB RXMH-2 relay delays the dropout time by approximately 20 milliseconds. The safety evaluation concluded that this 20 millisecond delay was not significant compared to the required accuracy of the sequencer, which is on the order of 200 milliseconds. However, the conclusion that the 20 millisecond time delay would not affect sequencer operation was incorrect. A problem with the auxiliary feedwater (AFW) pump start sequence was identified during the performance of the functional test, 2OST-36.3. With the exception of this relay timing problem, the team determined that the MDCP and associated 10 CFR 50.59 evaluation were adequate.

The installation and initial testing of the suppressors for the Train-A load sequencer was completed on November 14, 1993, with the final post-modification testing completed on November 16, 1993. The Train-B diode suppressors were installed and subsequently tested on November 17, 1993. In addition to the installation of the suppressors, microprocessor timer/relays 762-EGSAAX, 862-EGSAAX, and the 862-EGSBAX were replaced.

2.6.2 Auxiliary Feedwater Pump Logic Change

During the performance of the diesel generator 2-1 functional test 2OST-36.3, "Emergency Diesel Generator Automatic Tests," the auxiliary motor driven feedwater (AFW) pump inadvertently started immediately following the closure of the EDG output circuit breaker, rather than at load sequencer step 4. Load sequencer Step 4 equipment is supposed to load 15 to 17 seconds after the emergency diesel output circuit breaker closes. The licensee determined that the cause of the inadvertent start was a delay in the deenergization of auxiliary relay 162-EGSAAX, at the beginning of the loading sequence. The delay in the deenergization of the 162-EGSAAX relay was introduced by the addition of diode suppressors and was not identified during the development of the modification. The AFW pump starting logic is identical for Train-A and Train-B; therefore, only the Train-A starting logic will be described.

AFW Pump Starting Logic Operation

The motor driven auxiliary feedwater pump starting logic consisted of three contacts in series that were all required to close to start the AFW pump. (Not to be confused with the simplified schematic in Figures 1 and 2.) These contacts were closed when voltage was available on the emergency bus, when the load sequencer auxiliary relay 162-EGSAAX was energized (sequencer step 4), and when a safety injection signal was present. The load sequencer relay 162-EGSAAX was normally energized and deenergized when the EDG output circuit breaker closed. This logic was designed to deenergize the 162-EGSAAX relay before the voltage sensing relays on the emergency bus picked-up following power restoration by the EDG. Deenergizing the 162-EGSAAX relay opened a contact in the AFW pump starting logic that prevented starting the AFW pump prior to sequencer step 4. At sequencer step 4, the 162-EGSAAX relay energized and started the AFW pump.

AFW Pump Starting Logic Failure

After the failure of the functional test, the licensee reviewed the AFW pump starting circuit to determine why the AFW pump inadvertently started at sequencer step 1 rather than at step 4. During step 1 of the loading sequence, the safety injection (SI) contact in the AFW pump starting circuit was closed. The two additional contacts in the starting circuit were the 162-EGSAAX contact from the sequencer and the voltage available on the emergency bus contact from the bus voltage sensing relays. To prevent premature starting of the AFW pump, the 162-EGSAAX relay must deenergize prior to the voltage available on the bus sensing relays pick-up. This developed a race between the two relays. The installation of the suppressor diodes around the 162-EGSAAX relay caused a delay in the drop-out time of the 162-EGSAAX relay. This delay allowed the emergency bus voltage relay contacts to close prior to the opening of the 162-EGSAAX contacts, thus starting the AFW pump.

The modification which installed the diode suppressors did not assess the effect of the delay in auxiliary relay drop-out time on the sequencer operation. The associated safety evaluation identified that the expected delay in relay drop-out was approximately 20 milliseconds. The safety evaluation correctly stated that this would not adversely affect the overall delay time in loading safety-related equipment. However, the safety evaluation did not document the effect that this would have on the AFW pump start circuit. In addition the functional test measured the actual delay in relay drop-out time to be approximately 70 milliseconds.

Corrective Actions

In response to this failure, the licensee performed a detailed review of the sequencer circuit and verified that no other potential start logic problems existed. In order to correct the failure associated with the AFW pump starting circuit, the licensee initiated an Engineering Change Notice (ECN) to modify the AFW pump starting circuitry such that the 162-EGSAAX relay would not be energized prior to load sequence step 4. The design change prevents the possibility of having the three AFW pump starting circuit contacts closed prior to sequencer step 4. The 162-EGSAAX relay would be energized for 2 seconds at step 4 of the load sequence. An additional change to the AFW pump start circuit was required to provide a second AFW pump a start signal after the final sequencer step.

Conclusion

The implications of the installation of the diode suppressors on the relay timing were not thoroughly evaluated. Following the installation of the suppressors, the delay in slave relay drop-out time caused the AFW pump to start at the wrong sequence step. An additional design change was required to correct this problem. The team concluded that the actions taken by the licensee to correct this problem were acceptable. However, the team considered the inadequate evaluation of the suppressor installation on relay timing as another example of a weak design control process.

2.6.3 Post Modification Testing

After the installation of the suppressors, the modification design change package required the performance of sequencer testing to verify that the microprocessor timer/relays and the auxiliary relays were functioning properly. The modification design change package required that each sequencer train be tested a total of 30 times. Fifteen cycles were to be initiated by loss of normal power with an SI signal. The remaining fifteen cycles were to be initiated by loss of normal power with a CIB signal. The first and last run for each set of fifteen cycles were to be instrumented to allow for engineering review of the associated traces.

In addition to the testing required for the completion of the modification, other *in situ* tests were performed to verify that the installation of the of the suppression diodes allowed for proper sequencer operation. In total, approximately 200 *in situ* tests were performed with no failures. Whereas, *in situ* testing performed prior to the installation of the suppressors indicated a failure rate of approximately 35%. These post-modification tests verified the operation of the sequencer for loss of offsite power conditions, separately, and with a SI signal or a CIB signal. Approximately 20% of these tests were instrumented to verify that the voltage spikes were adequately suppressed, and to verify that the suppression diodes showed no signs of degradation. The licensee also performed the Operating Surveillance Tests 2OST-36.3 and 2OST-36.4, "Emergency Diesel Generator Automatic Tests," prior to declaring the sequencers operable. The team observed portions of these tests and determined that they were acceptable to demonstrate system operability.

2.7 Equipment Qualification

ATC Timer Relay Dedication

The Beaver Valley Unit 2 Updated Final Safety Analysis Report, Table 8.1-1, lists the Institute of Electrical and Electronic Engineers Standard (IEEE) 323-1974, "Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," as acceptance criteria for Class 1E components. This standard was used as guidance for the dedication of the ATC Model 365A microprocessor timer/relays.

The microprocessor timer/relays were procured as commercial grade items in the spring of 1990 and installed in the load sequencers in the fall of 1990. The dedication of the timer/relays as Class 1E components was controlled through the licensee's engineering design change process rather than through the commercial dedication program. The design change package stated that the following actions were necessary to dedicate the relays:

- A review and evaluation by a third party of the Class 1E environmental qualification of the microprocessor timer/relays. The review and evaluation was to be governed by IEEE 323-1974 (as interpreted by NUREG-0588, Rev. 1) and the seismic qualification requirements of IEEE 344-1975. The environmental qualification parameters specified in the procurement document were: temperature, pressure, humidity, cumulative radiation dose, aging, and seismic forces.

- An initial calibration and checkout of the relays prior to installation.

- A continuity test of the relay circuits to ensure that they were wired properly.

- A functional test of each sequencer circuit.

The third party review and evaluation was complete by Wyle Laboratories. The review was thorough, and provided adequate justification for qualification of the relays as specified in the procurement specification. However, the following deficiencies were noted in the licensee's overall qualification package for the microprocessor timer/relays (the combination of Wyle's testing and the onsite testing) when compared to the requirements of IEEE 323-1974:

- Electromagnetic interference (EMI) was not considered as part of the relay qualification. The term EMI encompasses both external (or radiated) EMI and circuit induced EMI. Section 6.2(2) of IEEE 323-1974 states that Class 1E qualification shall include electromagnetic interference.

- IEEE 323 requires specification of the equipment operating environment. The licensee indicated weakness in this area as illustrated by the following:

  (1) The equipment performance specifications did not define the transient range of voltage under which the relays were expected to operate.

  (2) The circuit configuration specified in the procurement specification was not the actual configuration used for all the relays. Some of the installed relays were wired with their clock power supplies continuously energized. The configuration qualified by Wyle had the relays energized only when the sequencer was called on to operate. This eventually led to failure of the relays as discovered in the spring of 1992. This deficiency was covered by Enforcement Action 92-085.

- The qualification documentation was not organized in a auditable form as specified in Section 8 of IEEE 323-1974. The documentation supplied by Wyle was thorough; however, the post-modification test results were not incorporated in the qualification documentation.

Following the sequencer failures on November 4 and 6, 1993, the licensee modified the sequencer design and performed supplemental testing to provide reasonable assurance that the ATC timer/relays installed in the load sequencers would operate as designed. They did not, however, develop an auditable qualification package for the relays. Additionally, no documentation was developed to indicate the status of the ATC timer/relays in the warehouse. The licensee's spare microprocessor timer/relays underwent third party review by Farwell & Hendricks, Inc. Since the spare microprocessor relays do not have auditable qualification documentation, and have not received rigorous testing like the installed relays, their Class 1E qualification requires documentation.

Suppression Diode Dedication

The team reviewed commercial grade evaluation, D-905786, for the suppression diodes. The critical characteristics defined by the licensee were appropriate for the intended application of the suppression diodes. Additionally, the commercial grade evaluation contained appropriate calculations to support the selection of the critical characteristics.

2.8 Generic Implications

Beaver Valley Specific

In addition to the microprocessor timer/relays installed in the sequencers, four additional ATC-365A microprocessor timer/relays are installed in the recirculation spray (RSS) pump starting circuits. These timer/relays start the RSS pumps 628 seconds after the receipt of a containment isolation phase-B (CIB) signal. A failure of the "D" RSS pump occurred during the performance of surveillance testing during the week of November 1, 1993. The timer/relay started the "D" RSS pump at the time the CIB signal was simulated and did not delay the pump start for 628 seconds. The timer/relay was removed from the circuit for further investigation and bench testing. During bench testing, 125 Vdc was inadvertently applied directly to the timer/relay without a voltage dropping resistor. The voltage dropping resistor was required to reduce the supply voltage to the timer/relay from the 125 Vdc to the design voltage of 24 Vdc. As a result of this error, the timer/relay was destroyed and was not available for further testing. A new timer/relay was installed in the RSS pump starting circuit and a functional test was successfully performed. The team considered the licensee's inadvertent damaging of the failed RSS pump microprocessor timer/relay as an example of weak troubleshooting practices.

Functional test 2BVT1.13.5, "Recirculation Spray Pump Test," was performed, with diagnostic test equipment installed, to determine if voltage spikes were affecting the performance of the RSS pump microprocessor timer/relays. The test identified one negative voltage spike at the microprocessor timer/relay input from the RSS pump breaker trip coil. During accident conditions, the RSS pump would not be tripped until the CIB signal had been reset. When the CIB signal is reset, the RSS pump microprocessor timer/relays are isolated from the RSS pump starting circuit. Therefore, any RSS pump breaker trip coil induced voltage spikes would not adversely affect the microprocessor timer/relay ability to start the RSS pump.

In order to determine if any other solid-state electronic relays had been installed at the Beaver Valley Power Station, the licensee reviewed the category one design change packages (DCPs) implemented over the past five years. This review identified four DCPs that installed solid-state electronic relays. The relays installed by these DCPs were determined to have adequate documentation regarding transient immunity that enveloped the expected transients conditions, or had been appropriately tested for surge withstand capability, fast transient and EMI susceptibility. Therefore, these relays should be suitable for their installed application.

Industry Generic Implications

The team determined that the load sequencer failures at Beaver Valley have generic implications. The generic issue is that licensees must conduct a thorough design review when replacing discrete component electrical devices with digital, microprocessor based electronic devices. Specifically, licensees need to conduct a detailed case-by-case design review to assure that the digital, microprocessor based replacement equipment is compatable for the specific application. This review is necessary since solid state electronic equipment is generally more susceptible to damage from system disturbances than their electromechanical predecessors, particularly with respect to electromagnetic interference and other power supply instabilities.

2.9 Commitments

The first three commitments listed below were provided in the licensee's letter to the NRC, dated November 18, 1993. In addition, the licensee staff stated that a review would be conducted to evaluate the feasibility of additional sequencer testing, and the commercial grade dedication package documentation for microprocessor timer/relays would be upgraded. It is the team's understanding that the licensee plans to do the following:

1. An ATC timer/relay will be sent to the manufacturer for failure analysis.

2. An evaluation of the licensee's capability to identify and specify modification tests which detect functional degradation of modified equipment will be conducted. Until completion of the evaluation, Engineering Assurance and System Engineers will review modification packages prior to installation and will concur with the modification testing requirements.

3. Engineering guidelines will be developed which address engineering requirements for the application of digital solid state components as replacements for non-digital components.

4. A review will be conducted to determine if additional testing of the emergency diesel generator sequencers is feasible and appropriate.

5. The qualification package for the ATC timer/relays will be upgraded to satisfy the IEEE-323-1974 standards. Documentation of the EMI type testing conducted on the ATC relay will be included in the commercial grade qualification package.

2.10 Conclusions

The modification which installed the Model 365A ATC microprocessor timer/relays was inadequate. The desig[illegible]rol for the selection and review for suitability of the ATC timer/relays for this [illegible]on was not adequate. The modification design inputs should have identified the potential for voltage spiking by the auxiliary relays. This design input should then have been translated into the equipment purchase specification and the dedication testing specification.

The implications of the installation of the diodes on relay timing was not thoroughly evaluated. The delay in the slave relay drop-out caused an auxiliary feedwater pump to start at the wrong sequence step following the installation of the diodes. Further design changes were required to correct this problem. The team concluded that the actions taken to correct this problem were acceptable.

The installation of the diodes to suppress voltage spikes was an acceptable corrective action. The team independently verified the test results and concluded that this modification makes the emergency diesel generator load sequencer operable.

Test control and trouble-shooting of the failed relays was weak. For example, the failed relay from the recirculation spray pump was inadvertently destroyed, preventing further investigative testing.

The corrective actions taken in response to the April 1992 clock failures were adequate. However, an opportunity to further evaluate the selection of the microprocessor timer/relays for this service application was missed at this time. The team concluded that the failure mechanism and corrective actions taken in response to the clock failures were independent of the current timer/relay failures.

The qualification documentation for the ATC 365A timer/relays was incomplete. The documentation did not address electromagnetic interference issues and was not put together in an organized and auditable format as specified in IEEE-323-1974.

3.0 EXIT MEETING

The team met with those denoted in Appendix A, on December 2, 1993, to discuss the preliminary inspection findings which are detailed in this report. The exit meeting was open for public observation and the NRC answered public questions following the exit meeting. The slides used at the exit meeting are provided as Attachment 2 of this inspection report.

APPENDIX A

Persons Contacted

Duquesne Light Company

* P. Bienick	Project Engineer
* L. Freeland	General Mgr. Nuclear Operations
* K. Grada	Mgr. Quality Services Unit
* K. Halliday	Director, Electrical Engineering
* F. Lipchick	Sr. Licensing Supr.
* D. McBride	System Engineer
* D. McLain	Mgr. Maintenance Engineering and Assessment
* T. Noonan	Gen. Mgr., Nuclear Engineering and Safety
* D. O'Neil	Gen. Mgr. Public Affairs
* J. Sasala	Director, Nuclear Communication
* R. Scheib	ANSS Unit 2
* J. Sieber	Sr. Vice President - Nuclear Power Division
* M. Siegel	Mgr. Nuclear Engineering Department
* G. Storolis	NSS Unit 2
* D. Szucs	Sr. Engineer, Nuclear Safety
* G. Thomas	Division Vice President - Nuclear Service
* N. Tonet	Mgr. Nuclear Safety
* G. Zupic	Supr. Reactor Engineering

U. S. Nuclear Regulatory Commission

* G. Edison	Project Manager, NRR
* C. Miller	Deputy Division Director, DRS
* L. Rossbach	Sr. Resident Inspector - Beaver Valley

Other

* G. Morris	Video Photographer
* J. Musala	Reporter
* B. Shaw	DLC-retired
* R. Barkanic	Nuclear Engineer, Pa. State DER/BRP

Asterisk (*) denotes those present at the exit meeting conducted on December 2, 1993. The persons contacted list is not a comprehensive list of every individual contacted but provides the principal staff associated with this event.

APPENDIX B

SEQUENCER OPERATION

The following provides a description of the function of the emergency diesel generator load sequencer operation. The Train-A and Train-B load sequencer operations are identical; therefore, only the Train-A sequencer operation will be described. A simplified logic diagram of this circuit is provided in Figure 1 of this inspection report.

Sequencer Operation

1. A loss of offsite power will result in the opening of the normal supply circuit breakers to the emergency bus and the automatic start of the associated emergency diesel generator. The opening of the normal supply circuit breaker to the emergency bus will cause the 52S-ENSAC contact to close.

2. Following the EDG attaining rated speed and voltage, the EDG output circuit breaker closes and contact 52S-ECPAA closes. This energizes master relay, 3-EGSAAX, because the 69-EGSAA and the 3-EGSAAX4 contacts are normally closed. Once the master relay is energized, its associated contacts in the circuits for the slave timer/relays are closed allowing the loads to sequence on in the proper order.

3. When an SI signal is present, contact SIS-K610XA would close.

4. The closing of contact SIS-K610XA provides power to the microprocessor timer/relay 762-EGSAA.

5. When microprocessor timer/relay 762-EGSAA energizes, its timer operation is started, and its normally open 762-INST contact closes.

6. At the closing of contact 762-INST, the SI/CIB reset relay, 3-EGSAAX4, energizes.

7. When relay 3-EGSAAX4 energizes, its normally closed contact in the master relay circuit opens, deenergizing the master relay and consequently all of its slave timer-relays.

8. At 0.5 seconds after energization of the 762-EGSAAX microprocessor timer/relay (step 3 above), its normally closed 762-TDO contact opens, deenergizing the SI/CIB reset relay, 3-EGSAAX4. The 762-TDO contact stays open until the 762-EGSAAX microprocessor timer/relay is reset (i.e. deenergized).

9. When the 3-EGSAAX4 relay deenergizes, its normally closed contact, which was opened as described in step 5 above, recloses and reenergizes the master relay, 3-EGSAAX, and all its slave timer/relays. Energizing these slave timer/relays allows the safety equipment to load in the proper sequence.

ATTACHMENT 1

AUGMENTED INSPECTION TEAM CHARTER

File

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

Docket No. 50-412

NOV 9 1993

MEMORANDUM FOR: Marvin W. Hodges, Director, Division of Reactor Safety

FROM: Thomas T. Martin, Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER FOR REVIEW OF COMMON MODE FAILURE OF THE EMERGENCY DIESEL GENERATOR LOAD SEQUENCERS AT BEAVER VALLEY UNIT 2

On November 4, 1993, during the load sequencing test of the 2-1 emergency diesel generator (EDG), the load sequencer malfunctioned in such a manner as to prevent automatic loading of the EDG. On November 6, 1993, a load sequencer malfunctioned on the 2-2 EDG. Subsequent testing revealed that a common-mode problem exists that may have prevented either EDG from loading automatically. In order to assess the safety significance of the issue, I have determined that an Augmented Inspection Team (AIT) should be initiated to review the causes and safety implications associated with these malfunctions.

The Division of Reactor Safety (DRS) is assigned the responsibility for the overall conduct of this Augmented Inspection. Jim Trapp, Team Leader, DRS, is appointed as Augmented Inspection Team Leader. Other AIT members are identified in Enclosure 2. The Division of Reactor Projects (DRP) is assigned the responsibility for resident and clerical support, as necessary; and the coordination with other NRC offices, as appropriate. Further, the Division of Reactor Safety, in coordination with DRP is responsible for the timely issuance of the inspection report, the identification and processing of potentially generic issues, and the identification and completion of any enforcement action warranted as a result of the team's review.

Enclosure 1 represents the charter for the Augmented Inspection Team and details the scope of the inspection. The inspection shall be conducted in accordance with NRC Management Directive (MD) 8.3, NRC Inspection Manual 0325, Inspection Procedure 93800, Regional Office Instruction 1010.1, and this memorandum.

William F. Kane /for
Thomas T. Martin
Regional Administrator

Enclosures:
1. Augmented Inspection Team Charter
2. Team Membership

Marvin W. Hodges 2 NOV 9 1993

cc w/encls:
J. Taylor, EDO
J. Sniezek, OEDO
T. Murley, NRR
J. Calvo, NRR
C. Rossi, NRR
W. Butler, NRR
F. Miraglia, NRR
C. McCracken, NRR
J. Wermiel, NRR
W. Russell, NRR
J. Wiggins, NRR
A. Thadani, NRR
B. Grimes, NRR
S. Varga, NRR
B. Boger, NRR
E. Jordan, AEOD
D. Ross, AEOD
V. McCree, OEDO
W. Kane, DRA, RI
R. Cooper, DRP, RI
W. Lanning, DRP, RI
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W. Lazarus, DRP, RI
W. Hehl, DRSS, RI
S. Shankman, DRSS, RI
L. Rossbach, SRI, Beaver Valley
G. Edison, NRR
C. Sisco, DRS, RI
L. Bettenhausen, DRS, RI
J. Linville, DRP, RI
K. Abraham, PAO, RI
M. Miller, SLO, RI

ENCLOSURE 1

AUGMENTED INSPECTION TEAM (AIT) CHARTER

The general objectives of this AIT are to:

1. Conduct a thorough and systematic review of the circumstances surrounding the failure of the diesel generator load sequencers.

2. Collect, analyze, and document relevant factual information to determine the causes, conditions, and circumstances pertaining to the failures, including the adequacy of commercial dedication qualification testing of the relays and the adequacy of the licensee's corrective actions in response to a previous failure of this circuitry (IR 50-412/92-07).

3. Evaluate the licensee's review of and response to the failures, including implemented and proposed corrective actions.

4. Assess the safety significance of the failures and communicate to Regional and Headquarters management the facts and safety concerns related to problems identified, including single failure vulnerabilities, impact on other safety systems, generic implications and the need for communication of generic issues to other licensees.

5. Evaluate modification controls, design changes, and surveillance testing which may have contributed to the failures.

6. Prepare a report documenting the results of this review for the Regional Administrator within thirty days of the completion of the inspection.

ENCLOSURE 2

AIT MEMBERSHIP

James Trapp, AIT Leader, Division of Reactor Safety (DRS), Region I (RI)

John Calvert, Reactor Engineer, Division of Reactor Safety (DRS), RI

Scott Greenlee, Resident Inspector, Beaver Valley Unit 1, DRP, RI

Richard Skokowski, Reactor Engineer, DRS, RI

Eric Lees, NRR

Other NRC personnel, consultants, or contractors will be engaged in this AIT, as needed.

ATTACHMENT 2

AUGMENTED INSPECTION TEAM

EXIT MEETING SLIDES

AUGMENTED INSPECTION TEAM
BEAVER VALLEY UNIT 2

EMERGENCY DIESEL GENERATOR LOAD SEQUENCER FAILURES

NRC INSPECTION 50-412/93-81

EXIT MEETING

DECEMBER 2, 1993
10 a.m.

- **EXIT MEETING BETWEEN NRC AND LICENSEE.**

- **NRC WILL ADDRESS PUBLIC QUESTIONS REGARDING TEAM FINDINGS.**

1

BEAVER VALLEY UNIT 2
LOAD SEQUENCER FAILURES

INSPECTION SCOPE

- CONDUCT A THOROUGH AND SYSTEMATIC REVIEW OF THE CIRCUMSTANCES SURROUNDING THE FAILURE.
- COLLECT AND ANALYZE FACTUAL INFORMATION, INCLUDING THE COMMERCIAL GRADE DEDICATION OF THE FAILED TIMER/RELAYS.
- REVIEW THE ADEQUACY OF THE CORRECTIVE ACTIONS TAKEN IN RESPONSE TO THE PREVIOUS SEQUENCER FAILURE.
- REVIEW THE PROPOSED CORRECTIVE ACTIONS.
- EVALUATE THE MODIFICATION AND ANY SURVEILLANCE TESTING THAT MAY HAVE CONTRIBUTED TO THIS FAILURE.
- ASSESS THE SAFETY SIGNIFICANCE OF THE FAILURES.
- DETERMINE IF THIS EVENT HAS GENERIC IMPLICATIONS.

BACKGROUND

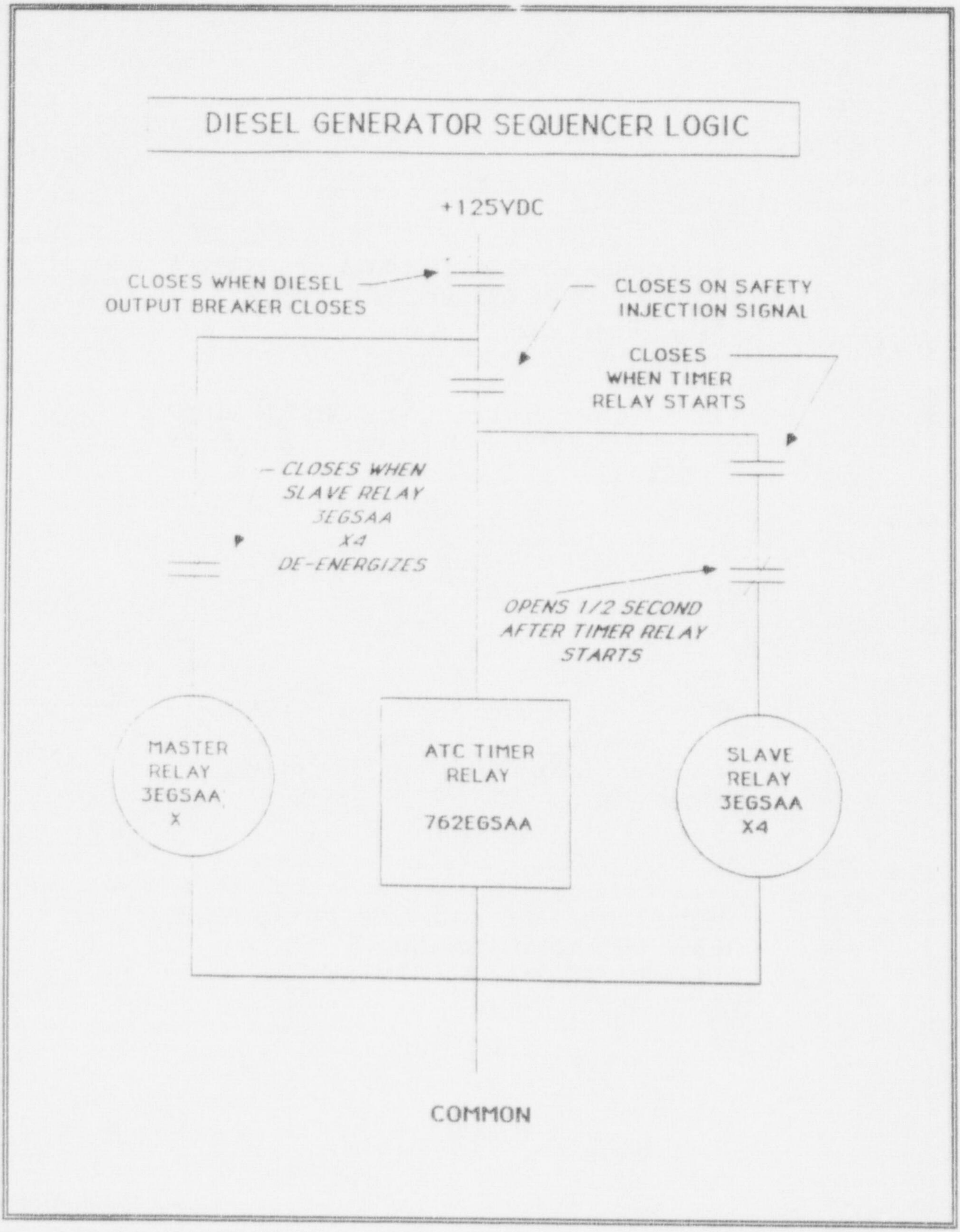
- EMERGENCY DIESEL GENERATOR LOAD SEQUENCER AUTOMATICALLY STARTS EQUIPMENT REQUIRED TO MITIGATE THE CONSEQUENCES OF AN ACCIDENT WHEN OFFSITE POWER IS LOST.
- ORIGINALLY THE TIMER/RELAYS WERE ATC MODEL 305E AND WERE NOT MICROPROCESSOR BASED.
- DURING REFUELING OUTAGE (RFO) 2, IN 1990, THE TIMER/RELAYS WERE REPLACED WITH MICROPROCESSOR BASED ATC MODEL 365A TIMER/RELAYS.
- IN 1992 SIX ATC TIMERS WERE IDENTIFIED AS FAILED DUE TO INTERNAL CIRCUIT CLOCK FAILURES.
- THE NRC ISSUED A SEVERITY LEVEL III VIOLATION AND CIVIL PENALTY IN RESPONSE TO THE ATC TIMER/RELAY CLOCK FAILURES.

EVENT DESCRIPTION

- ON NOVEMBER 4, 1993, DURING ROUTINE SURVEILLANCE TESTING, THE 2-1 EMERGENCY DIESEL GENERATOR LOAD SEQUENCER FAILED TO FUNCTION.
- ATC TIMER/RELAY 762 WAS REPLACED AND THE SURVEILLANCE TEST WAS SUCCESSFULLY COMPLETED.
- ON NOVEMBER 5, 1993, DURING ROUTINE SURVEILLANCE TESTING, THE 2-2 EMERGENCY DIESEL GENERATOR LOAD SEQUENCER FAILED TO FUNCTION.
- THE LICENSEE NOTIFIED THE NRC OF THE FAILURES ON NOVEMBER 6, 1993.
- IT APPEARED THAT A COMMON CAUSE FAILURE HAD AFFECTED MULTIPLE TRAINS OF A SAFETY SYSTEM.
- AN AIT WAS DISPATCHED BY THE NRC REGIONAL ADMINISTRATOR AND ARRIVED ONSITE ON NOVEMBER 9, 1993.

SAFETY SIGNIFICANCE

- THE DIESEL GENERATOR LOAD SEQUENCER WOULD NOT AUTOMATICALLY START EMERGENCY EQUIPMENT.
- THE FAILURE WOULD ONLY OCCUR DURING A LOSS OF OFFSITE POWER WHEN A SAFETY INJECTION WAS REQUIRED.
- MANUAL OPERATOR ACTIONS WOULD BE REQUIRED TO LOAD SAFETY-RELATED EQUIPMENT.
- RESETTING OF THE MOTOR-CONTROL-CENTERS WOULD REQUIRE OPERATOR ACTIONS FROM OUTSIDE THE CONTROL ROOM.
- THE TEAM DETERMINED THAT THE SAFETY SIGNIFICANCE OF THIS EVENT WAS HIGH BECAUSE A COMMON CAUSE FAILED REDUNDANT TRAINS OF SAFETY-RELATED EQUIPMENT.


DIESEL GENERATOR SEQUENCER LOGIC
+125VDC
CLOSES WHEN DIESEL OUTPUT BREAKER CLOSES
CLOSES ON SAFETY INJECTION SIGNAL
CLOSES WHEN TIMER RELAY STARTS
CLOSES WHEN SLAVE RELAY 3EGSAA X4 DE-ENERGIZES
OPENS 1/2 SECOND AFTER TIMER RELAY STARTS
MASTER RELAY 3EGSAA X
ATC TIMER RELAY
762EGSAA
SLAVE RELAY 3EGSAA X4
COMMON

CORRECTIVE ACTIONS

- A NUMBER OF BENCH AND INSITU TESTS WERE PERFORMED TO DETERMINE THE CAUSES OF THE EQUIPMENT FAILURE.
- DIODES WERE INSTALLED AROUND THE SLAVE RFLAYS TO REDUCED THE MAGNITUDE OF THE VOLTAGE SPIKES CAUSED BY THE DROPOUT OF THESE RELAYS.
- THREE ATC TIMER\RELAYS IN THE SEQUENCER WERE REPLACED WITH NEW TIMER/RELAYS.
- POST MODIFICATION TESTING IDENTIFIED A PROBLEM WITH THE AUXILIARY FEEDWATER PUMP STARTING LOGIC.
- ADDITIONAL SEQUENCER AND PUMP STARTING LOGIC DESIGN CHANGES WERE REQUIRED TO ELIMINATE THE AUXILIARY FEEDWATER PUMP LOGIC PROBLEM.
- EXTENSIVE POST MODIFICATION TESTING OF THE LOAD SEQUENCERS WAS CONDUCTED TO DEMONSTRATE OPERABILITY AND RELIABILITY.

GENERIC IMPLICATIONS

- THE LICENSEE REVIEWED DESIGN CHANGES MADE TO BOTH BEAVER VALLEY 1 AND 2 TO VERIFY NO SIMILAR CONDITIONS EXISTED.

- A DESIGN CHANGE MADE TO THE RECIRCULATION SPRAY PUMP LOGIC WAS IDENTIFIED AS CONTAINING SIMILAR ATC TIMER/RELAYS.

- THE SPIKES IDENTIFIED IN THE RECIRCULATION SPRAY PUMP LOGIC WERE DETERMINED TO NOT AFFECT ATC TIMER/RELAY OPERATION.

- THE NRC IS CURRENTLY PLANNING TO ISSUE AN INFORMATION NOTICE DESCRIBING THIS EVENT.

COMMITMENTS

- A FAILURE ANALYSIS WILL BE CONDUCTED ON AN ATC TIMER/RELAY.
- THE FEASIBILITY OF ADDITIONAL SEQUENCER TESTING WILL BE INVESTIGATED.
- THE QUALIFICATION PACKAGE FOR THE ATC TIMER/RELAYS WILL BE UPGRADED.
- AN EVALUATION OF POST MODIFICATION TESTING WILL BE CONDUCTED.
- ENGINEERING GUIDELINES FOR REPLACEMENTS WITH DIGITAL SOLID STATE COMPONENTS WILL BE DEVELOPED.

8

CONCLUSIONS

- THE MODIFICATION THAT INSTALLED THE MODEL 365A, ATC TIMER/RELAYS WAS INADEQUATE.
- A WEAK TECHNICAL UNDERSTANDING OF THE MODEL 365A TIMER/RELAY LIMITATIONS, APPLICATIONS AND SPECIFICATIONS BY THE ENGINEERING DEPARTMENT WAS THE ROOT CAUSE FOR THIS FAILURE.
- THE CORRECTIVE ACTION THAT INSTALLED DIODES TO SUPPRESS THE VOLTAGE SPIKES WAS ACCEPTABLE.
- TROUBLE-SHOOTING ACTIVITIES AND TESTING FOLLOWING THE FAILURE WERE POORLY PLANNED AND WERE FREQUENTLY NOT FORMALLY DOCUMENTED.
- THE QUALIFICATION DOCUMENTATION FOR THE ATC TIMER/RELAYS WAS INCOMPLETE.
- THE CORRECTIVE ACTIONS TAKEN IN RESPONSE TO THE PREVIOUS CLOCK CIRCUIT FAILURE WERE APPROPRIATE AND WERE INDEPENDENT OF THE CURRENT FAILURE.

ENFORCEMENT ACTIONS

- AN NRC ENFORCEMENT CONFERENCE WILL BE SCHEDULED TO DISCUSS THE EVENTS AND CIRCUMSTANCES SURROUNDING THE FAILURE OF THE EMERGENCY DIESEL GENERATOR LOAD SEQUENCERS.

Figure 1

12241-E-12A Sh.1 (Simplified) - Before Modification

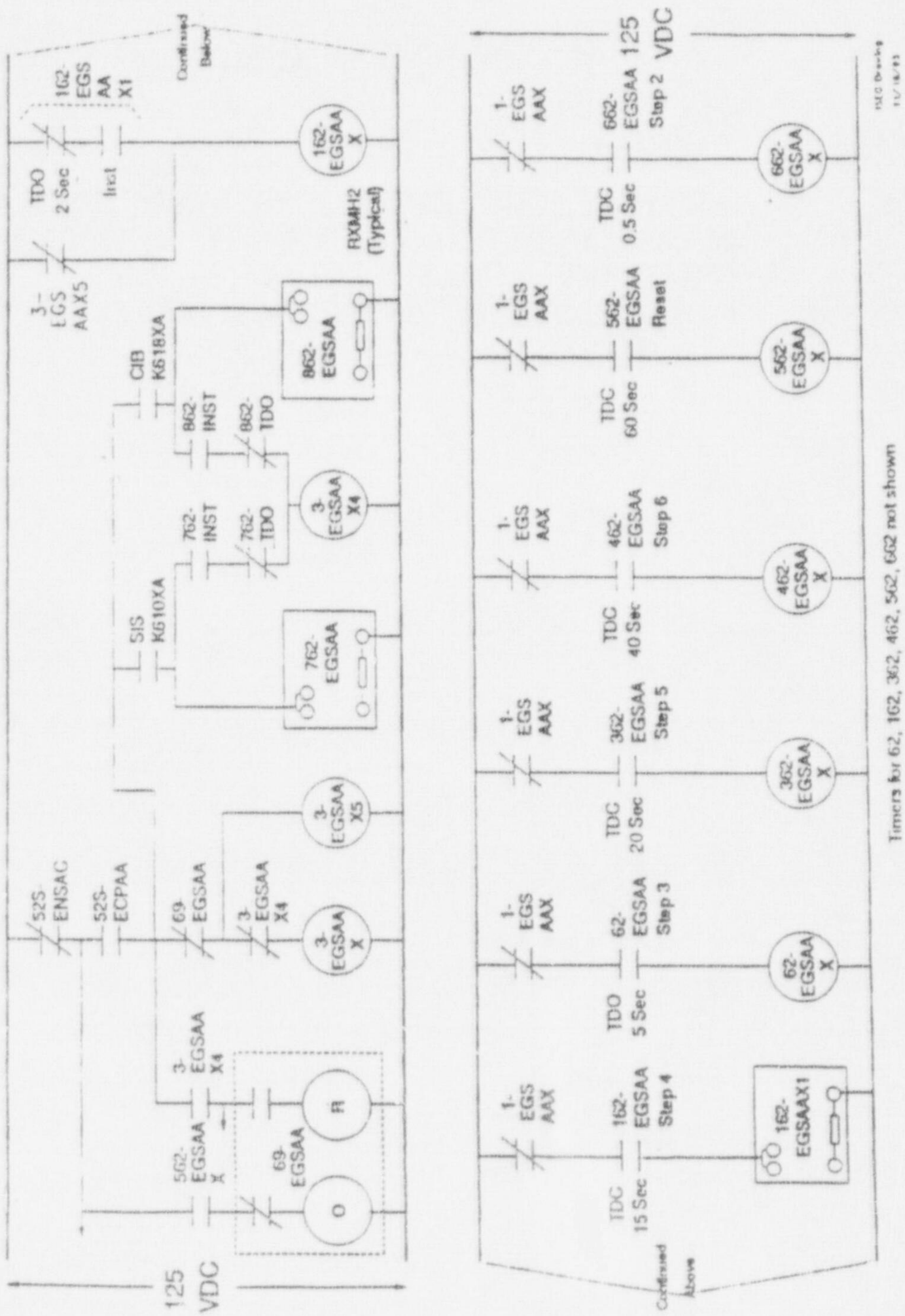
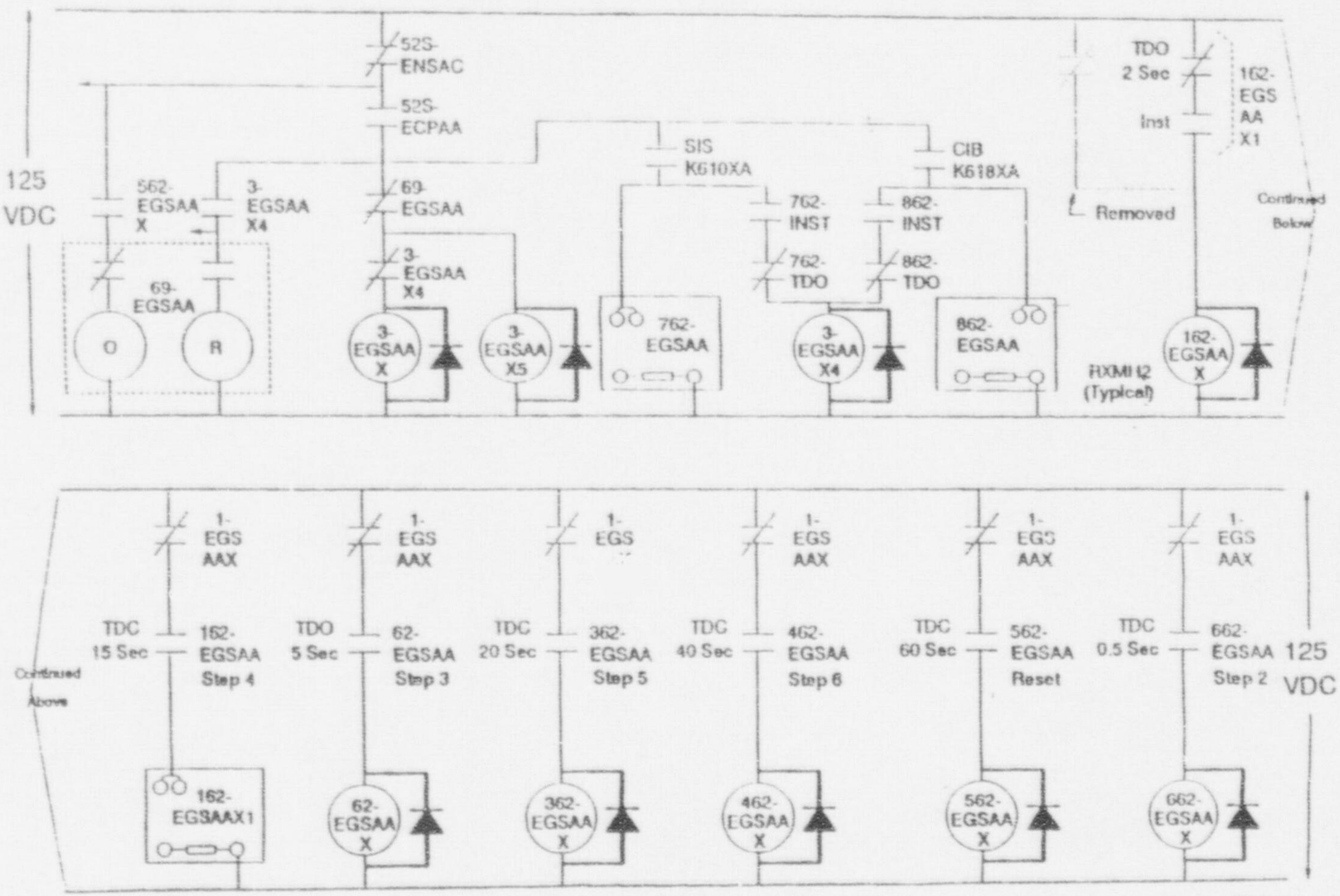


Figure 2

12241-E-12A Sh.1 (Simplified) - After Modification



Timers for 62, 162, 362, 462, 562, 662 not shown

AIT No. 440/93-06
Perry

APR 15 1993

Docket No. 50-440

Centerior Service Company
ATTN: Mr. Robert Stratman
Vice President
Nuclear - Perry
c/o The Cleveland Electric Illuminating
Company
10 Center Road
Perry, OH 44081

Dear Mr. Stratman

The enclosed report refers to a special onsite review by an NRC Augmented Inspection Team (AIT) on March 27, 1993, through April 2, 1993, relative to the service water pipe break at the Perry Nuclear Power Plant on March 26, 1993, and the subsequent flooding in some areas in the plant. The team was composed of Messrs. R. D. Lanksbury, J. F. Schapker, A. Vegel, and J. G. Guzman of this office; Dr. R. B. Landsman of this office; and Mr. G. P. Hornseth of the Office of Nuclear Reactor Regulation (NRR). The report also refers to the followup activities of your staff and to the discussion of our findings with Mr. D. P. Igyarto and others of your staff at the conclusion of the inspection.

The enclosed copy of our Augmented Inspection Team report identifies areas examined during the inspection. Within these areas, the inspection consisted of a selective examination of procedures, and representative records, observations, and interviews with personnel.

The Augmented Inspection Team was formed to gather information on the event. Specifically, the team examined your response to the event, effects of flooding, root causes of the pipe break, and proposed corrective actions. It is not the responsibility of an Augmented Inspection Team to determine compliance with NRC rules and regulations or to recommend enforcement actions. These aspects will be reviewed in a subsequent inspection.

The consequences of the event posed no threat to public health and safety. A minor gaseous radiological release occurred but was not directly attributable to the event. The release was minimal and well below regulatory limits. Response to the event required a rapid reactor shut down, including a manual reactor scram, and the consequent actuation of safety equipment. All equipment operated as expected during recovery from the event. No significant operational safety parameters were approached or exceeded. Internal plant flooding was limited and did not reach a level that could affect safety-related equipment.

The pipe rupture is believed to have resulted from a small perforation and leak in the pipe which slowly grew in size due to erosion. Several potential root causes for development of the initial perforation were identified. However, the failure analysis effort was hampered by the fact that substantial

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portions of the failed pipe were lost at the time of pipe rupture. As a result, a single root cause could not be determined; furthermore, it is unlikely that additional investigation will yield an answer. The team does believe that the conditions which led to the pipe rupture were localized. The local failure mechanism concept appears to be supported by the absence of widespread cracking which would result from excessive bending or other gross loads during service. Inspection of the limited sections of service water system piping that could be observed by the team indicated that no system wide degradation appeared to have occurred.

Your initial recovery from the event was thorough. However, corrective actions from a similar event in December 1991 had only partiality been implemented and, as a result, internal flooding that had occurred previously occurred again through the same or similar pathways. At the conclusion of this inspection you had not yet completed formulating your corrective actions for this event. As a result, the team was unable to review them. We understand that you will provide your corrective actions as specified in the Confirmatory Action Letter (CAL) dated March 30, 1993. We will continue to closely follow your repair efforts and other corrective actions that you plan. We also understand that you are evaluating the feasability of performing periodic inspections of the service water system. We would appreciate you addressing this issue in your response to the CAL.

The team concluded that the operators safely responded in an excellent manner to the event and that their actions were indicative of a strong knowledge of plant systems and procedures.

In accordance with 10 CFR 2.790 of the Commission's regulations, a copy of this letter and the enclosed inspection report will be placed in the NRC Public Document Room.

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

ORIGINAL SIGNED BY HUBERT J. MILLER

A. Bert Davis
Regional Administrator

Enclosure: AIT Report
No. 50-440/93006(DRS)

See Attached Distribution

RIII	RIII	RIII	RIII	RIII	NRR
Lanksbury	Landsman	Schapker	Vegel	Guzman	Hornseth
RIII	RIII	RIII	RIII		
Greger	Martin	Miller 4/15/93	Davis 4/15/93		

Centerior Service Company 2 APR 1 5 1993

were lost at the time of pipe rupture. However, the team believes that the cause of the pipe rupture was local to the failure location and was not the result of general system wide degradation. The local failure mechanism concept appears to be supported by the absence of widespread cracking which would result from excessive bending or other gross loads during service. Visual examination of exposed portions of the pipe, and the portions of the pipe removed during excavation, indicated that no significant system wide degradation or damage appeared to have occurred. However, due to the brittle nature of fiberglass pipe, it is susceptible to local damage. The possible existence of other locally degraded locations cannot be ruled out without a detailed inspection of the rest of the service water system.

Your initial recovery from the event was thorough. However, corrective actions from a similar event in December 1991 had only partiality been implemented and, as a result, internal flooding that had occurred previously occurred again through the same or similar pathways.

The team concluded that the operators safely responded in an excellent manner to the event and that their actions were indicative of a strong knowledge of plant systems and procedures.

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Sincerely,

A. Bert Davis
Regional Administrator

Enclosure: AIT Report
No. 50-440/93006(DRS)

See Attached Distribution

RIII	RIII	RIII	RIII	RIII	NRR
Lanksbury 4/14/93	Landsman 4/14/93	Schapker 4/14/93	Vegel 4/14/93	Guzman 4/14/93	Hornseth 4/14/93
RIII	RIII	RIII	RIII		
Greger	Martin 4/14	Miller	Davis		

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bcc: PUBLIC

AUGMENTED INSPECTION TEAM REPORT

U.S. NUCLEAR REGULATORY COMMISSION

PERRY UNIT 1 SERVICE WATER PIPE BREAK

APRIL 15, 1993

INSPECTION REPORT NO. 50-440/93006(DRS)

TABLE OF CONTENTS

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-440/93006(DRS)

Docket No. 50-440 License No. NPF-58

Licensee: Cleveland Electric Illuminating Company
Post Office Box 5000
Cleveland, OH 44101

Facility Name: Perry Nuclear Power Plant

Inspection At: Perry Site, Perry OH

Inspection Conducted: March 27, 1993 - April 2, 1993

Inspectors: R. B. Landsman, DRP
J. F. Schapker, DRS
J. G. Guzman, DRS
G. P. Hornseth, NRR
A. Vegel, Resident Inspector - Perry

Approved By: Roger D. Lanksbury, Team Leader 4/14/93 Date

Approved By: T. O. Martin, Acting Director, Division of Reactor Safety 4/14/93 Date

Inspection Summary

Inspection on March 27, 1993, - April 2, 1993 (Report No. 50-440/93006(DRS)

Areas Inspected: Special Augmented Inspection Team (AIT) inspection conducted in response to the service water pipe break event at Perry Nuclear Power Plant on March 26, 1993. The review included validation of the sequence of events, evaluation of the root cause for the pipe break, review of the service water system's performance and maintenance history, evaluation of operator response to the event, evaluation of the effects of flooding, evaluation of the licensee's event classification and reporting, and evaluation of the licensee's corrective actions to the December 1991 circulating water pipe break.

Results: No violations or deviations were identified in any of the areas inspected. No significant operational safety parameters were approached or exceeded. Four radial breaks in the pipe were identified. Two were about 5-inches apart and appeared to be the location where the pipe rupture occurred. Two secondary pipe breaks, one on either side of the rupture location, were also identified. The team concluded that the root cause of the failure was an initial perforation that slowly grew and ultimately resulted in the pipe rupture. Several potential root causes for development of the initial perforation were identified. However, the failure analysis effort was hampered by the fact that substantial portions of the failed pipe were lost at the time of pipe rupture. There was evidence that the pipe leaked for a significant time period prior to the rupture. No pipe joint was involved in the failure. The team did believe that the cause of the pipe rupture was localized and was not the result of general system wide degradation. The local failure mechanism concept appeared to be supported by the absence of widespread cracking which would result from excessive bending or other gross loads during service. Visual examination by the team of exposed portions of the pipe, and the portions of the pipe removed during excavation, indicated that no other significant degradation appeared to have occurred. The secondary pipe breaks appeared to be the result of unsupported soil and asphalt caving in after the water flow was stopped.

The team concluded that the operators responded in an excellent manner and that their actions were indicative of a strong knowledge of plant systems and procedures.

1.0 Introduction

1.1 Event Summary

On March 26, 1993, at about 3:22 p.m. (EST) a nonsafety-related 30-inch fiberglass pipe carrying service water (SW) from the SW pump house to the Unit 1 turbine building catastrophically failed approximately 13-feet underground causing the asphalt covered ground to heave up. The break was located in the west plant yard approximately 50-feet south of the water treatment building. Water from the pipe break flooded the western portion of the site and entered various plant buildings causing minor flooding (up to 6 to 8-inches) of areas inside the plant. The entry points were primarily through electrical conduits connected to flooded electrical manholes in the vicinity of the pipe break. Secondary entry points were from flow under various doors on the exterior of the buildings. Reactor operators commenced a fast reactor shut down and manually scrammed the reactor from about 66 percent power at approximately 3:26 p.m. Under the licensee's emergency plan an Alert was declared at 3:35 p.m. due to flooding. The SW leak was stopped approximately 16-minutes after the pipe rupture when the operators stopped the SW pumps. The plant was placed in cold shutdown at 10:10 p.m. on March 26, and the Alert was terminated on March 27 at 1:05 a.m.

The resident inspectors responded to the event. A subsequent review by the residents and licensee personnel indicated that no safety-related equipment was affected by the flooding. Some water entered the high pressure core spray (HPCS) pump room, apparently by dripping down through the pump maintenance access hatches above the pump, and a small amount of water conveyed through electrical conduits entered the emergency service water pump house. No water was observed in any of the remaining rooms containing emergency core cooling system (ECCS) equipment. Some nonsafety-related equipment, such as the offgas system glycol control panel, was affected. Radioactive contamination of basement floor areas in several of the site buildings resulted from flood waters flowing through existing contaminated areas and from floor drains backing-up.

1.2 Augmented Inspection Team (AIT) Formation

Region III staffed the Incident Response Center (IRC) and headquarters personnel monitored the event. Senior NRC managers determined that an AIT was warranted to gather information on the SW pipe break. On Saturday, March 27, 1993, an AIT was formed consisting of the following personnel:

Team Leader: R. D. Lanksbury, Chief, Reactor Projects Section 3B, Division of Reactor Projects (DRP)

Team Members: R. B. Landsman, Project Inspector, Section 1A, DRP
J. F. Schapker, Reactor Inspector, Materials and Processes Section, Division of Reactor Safety (DRS)
A. Vegel, NRC Resident Inspector, Perry Nuclear Power Plant, DRP
J. G. Guzman, Reactor Inspector, Materials and Processes Section, DRS
G. P. Hornseth, Materials Engineer, Materials and Chemical Engineering Branch, Office of Nuclear Reactor Regulation (NRR)

The team leader and two of the team members were on site by the evening of March 27. The full team was on site the morning of March 29. In parallel with formation of the AIT, Region III issued a Confirmatory Action Letter (CAL) (Attachment 1) on March 30, which confirmed certain actions in support of the team.

1.3 AIT Charter

A charter was formulated for the AIT and transmitted from Edward G. Greenman to Roger D. Lanksbury on March 27, 1993, (Attachment 2) with copies to appropriate EDO, NRR, AEOD, and Region III personnel.

The AIT was terminated on Friday, April 2, 1993.

2.0 Description of the Event

2.1 Service Water System Description

The purpose of the nonsafety-related service water (SW) system was to provide cooling water to various auxiliary mechanical equipment throughout the turbine, auxiliary, and radwaste buildings, and the control complex. The system was capable of removing heat given up by various nonsafety-related heat exchangers including the turbine building closed cooling (TBCC) heat exchangers, the turbine lube oil coolers, and the nuclear closed cooling (NCC) heat exchangers. The system design included four one-third capacity vertical wet pit pumps, each with a total discharge head (TDH) of 140-feet (nominally 60 psig) at a design capacity of 23,500 gpm. SW flow was through a once-through open loop piping network where lake water was pumped through the tube side of the heat exchangers being cooled and was then returned to the lake by way of discharge tunnel return lines. The system also supplied makeup water to the cooling tower basins and to the screen wash pumps.

Piping throughout the system was either carbon steel or fiberglass reinforced plastic (FRP) and is non-seismic category I. FRP piping was used exclusively in the portions of the system which were installed underground or outdoors and was constructed to meet the requirements of the American Society of Chemical Engineers (ASCE) Manuals and Reports on Engineering, Practices #37, for plastic pipe and the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section X. SW flow was routed from the SW pump house to the plant through an underground 54-inch diameter FRP pipe (see Figure 1 for a general SW piping arrangement). The fiberglass supply lines were designed to Line Specification P16-7 which had a design pressure of 100 psig. Normal operating pressures were in the 40 psig range.

As the 54-inch FRP pipe approached the plant, a 30-inch FRP pipe branched off at 90 degrees to direct flow to the Unit 1 turbine building. It was this line that experienced the break. The 54-inch pipe then transitioned to a 48-inch FRP pipe and then to a 42-inch FRP pipe that supplied flow to the control complex. A branch line from the 48-inch pipe that went to Unit 2 had been sealed off. The FRP piping transitioned to carbon steel piping at the building penetrations.

Piping for the SW system inside the plant was carbon steel. As the SW piping exited the plant, it converted back to FRP piping. Underground FRP piping was used to return the SW to the discharge tunnel. The lower pressure FRP discharge lines were designed to Line Specification R16-7 which had a design press[illegible] 50 psig. The operating discharge pressure was normally about 9 psi

2.2 Sequence of Events

At 1:14 p.m. (EST) on March 26, 1993, with the plant at 100 percent reactor power, plant personnel reported water coming up from the perimeter of a concrete slab on which a trash compactor and dumpster were sitting and a concrete slab for one of the underdrain system manways. The surrounding areas were covered with asphalt. The concrete slabs were located in the area south of the water treatment building. Witnesses initially reported water bubbling up approximately 4-inches. The water was coming from the asphalt-to-concrete joint around three sides of the concrete slabs. After discovery, the licensee att[illegible]d to determine the source of the leak by stopping flow through the und[illegible]nd piping systems known to be in the area (emergency service water (ESW, [illegible]d condensate transfer) with the exception of service water (SW) which could not be isolated during plant operation. Stopping flow through ESW at 1:28 p.m. showed no affects to the water leaking from the pavement. Subsequent plant walkdowns showed no intrusion of water in the plant. At 2:47 p.m., isolation of condensate transfer system underground piping showed no effects on the leakage flowrate. Plant walkdowns were still reporting no water intrusion. Water continued bubbling up from the pavement and the licensee concluded that the water was the result of a SW leak and that a plant shut down would be required. At 3:22 p.m., low SW discharge pressure (24 psig) was noted and the fourth (of four) SW pumps was started in accordance with plant procedures. At about this same time, people in the vicinity of the leak observed the asphalt heave up with a substantial increase in the amount of water coming from the area.

At 3:25 p.m., the Shift Supervisor ordered a fast reactor shut down in accordance with off normal instruction (ONI)-P41 (Loss of Service Water) due to the rupture of a 30-inch SW line. The fast reactor shut down reduced reactor power to 66 percent and a manual scram was initiated at 3:26 p.m. Plant emergency instruction (PEI)-B13 (Reactor Pressure Vessel Control) was entered when reactor vessel water level dropped to level 3 (178-inches above the top of active fuel). At approximately 3:27 p.m. the main turbine was manually tripped. At about this same time plant personnel provided the first reports of water intrusion into the plant. By 3:30 p.m., water had entered the service, intermediate, diesel, radwaste, turbine, offgas, and auxiliary buildings as well as the control complex.

An Alert was declared at 3:35 p.m. based on flooding and at 3:38 p.m. the SW system was shut down. The motor driven feedwater pump was also started at 3:38 p.m. in accordance with the reactor scram procedure (ONI-C71-1). Reactor level control was shifted from the feedwater system to the reactor core isolation cooling (RCIC) system at 3:41 p.m. due to the impending loss of the condensate system. By 3:52 p.m., both residual heat removal (RHR) pumps "A" and "B" were operating in the suppression pool cooling mode to remove the heat loads added by the RCIC system. At 3:55 p.m. reactor recirculation (RR) pump "B" was shut down.

At 4:12 p.m. water levels in the plant were reported to be decreasing and were down to 2-inches in the control complex from a high of 6 to 8-inches. PEI-B13 was exited at 4:20 p.m. and integrated operating instruction (IOI)-7 (Cooldown Following Reactor Scram, Main Condenser Available) was entered. At 4:45 p.m., reactor pressure control was shifted from the bypass valves to the safety relief valves (SRVs) and the operators began closing the main steam isolation valves (MSIVs) and steam line drain valves. At 4:47 p.m. the "C" and "D" outboard MSIVs were closed. At 4:48 the inboard "C" and "D" MSIVs and the inboard and outboard "B" MSIVs were closed. At 4:53 p.m. the inboard and outboard "A" MSIVs and the inboard steam line drain valves were closed. The initial SRV opening for pressure control occurred at 4:51 p.m. and main condenser vacuum was broken at 4:55 p.m. A total of 10 SRV openings occurred during the event. The low condenser vacuum resulted in an MSIV isolation signal at 4:58 p.m.; however, all the MSIVs and the inboard drain valves had already been manually closed.

A high suppression pool level (18-feet 6-inches) resulted in entering PEI-T23 (Containment Control) at 5:10 p.m.. At 5:29 p.m., IOI-6 (Cooldown Following Reactor Scram, Main Condenser Not Available) was entered. The SW system shutdown resulted in high turbine building closed cooling (TBCC) system heat exchanger outlet temperatures at 6:19 p.m. and high nuclear closed cooling (NCC) system heat exchanger outlet temperatures at 7:39 p.m. Equipment that was normally cooled by SW through these heat exchangers was either secured by the operators, or cooling was transferred to the emergency service water (ESW) system. At 7:08 p.m. indications of high hydrogen concentrations in the drywell and containment were detected. PEI-M51/56 (Drywell and Containment Hydrogen Control) was entered and at 7:12 p.m. the hydrogen igniters were energized. At 8:15 p.m. shutdown cooling using RHR "A" was established.

RCIC tripped at 8:18 p.m. on a reactor water level 8 trip and level control was transferred to the control rod drive system. At 8:45 p.m., RR pump "A" was secured.

The plant was placed in cold shutdown at 10:10 p.m. on March 26 and the Alert was terminated on March 27 at 1:05 a.m. After analyzing samples of the drywell and containment atmospheres and determining that a hydrogen problem did not exist, the hydrogen igniters were de-energized at 1:25 a.m.

2.3 Precursors to the Event

Prior to and at the time of this event, the reactor was at steady state 100 percent power with no plant evolutions in progress that could impact on the SW system. The SW system had been operating steady state since March 25, 1993, when SW pumps were shifted. SW pumps were routinely shifted every 2-weeks. Based on the team's review of plant logs and interviews with operators, no ongoing activities that could have been precursors to the pipe rupture were identified.

2.4 Operator Response

To determine what actions the operators took in response to the event and the suitability of these actions, the team reviewed plant logs, the Post Scram Restart Report (1-93-01), appropriate plant emergency and off-normal procedures, and interviewed the operators involved in the event.

Prior to the event on March 26, 1993, the reactor was at 100 percent reactor power with no major evolutions or plant transients in progress. The operators in the control room were cognizant of the water leak adjacent to the water treatment building and were involved in determining the source of the leak. At 3:22 p.m. (EST) a service water (SW) pump discharge header pressure low alarm was received and a fourth SW pump was started in accordance with off normal instruction (ONI)-P41 (Loss of Service Water). At 3:25 p.m., the shift supervisor at the scene reported that the SW leak had increased dramatically, and ordered the Unit Supervisor to shut down the plant. A fast reactor shutdown was conducted. Core flow was lowered to 52 million pounds mass per hour and the reactor was manually scrammed from approximately 66 percent reactor power. As a result of the scram, an expected reactor water level 3 actuation was received which resulted in the operators entering plant emergency instruction (PEI)-B13 (Reactor Pressure Vessel Control). By 3:30 p.m., reactor water level was stabilized and a cooldown was commenced utilizing the reactor core isolation cooling (RCIC) system for level control and steam bypass valves for pressure control.

Concurrent with plant cooldown and emergency plant activities, actions were in progress to minimize the impact of the SW pipe rupture. Plant equipment normally cooled by SW through the nuclear closed cooling or turbine building closed cooling systems were secured or realigned. The condensate and feedwater systems, and reactor water cleanup system, and one of the recirculation pumps were shut down. Control complex chillers were transferred to the emergency closed cooling system, and spent fuel pool heat exchangers were aligned to be cooled by the emergency service water system. In addition, both residual heat removal (RHR) systems were lined up for suppression pool cooling in anticipation of temperature increases due to RCIC operation.

Approximately 1 hour after the reactor scram, the steam supply to the main turbine gland seals was lost due to the steam seal evaporator having no condensate makeup supply. As a result, condenser vacuum was eventually lost. Prior to breaking condenser vacuum, reactor pressure control was transferred to the safety relief valves (SRVs). With the loss of condenser vacuum, a main steam line isolation signal was received, closing the outboard main steam line drain valves. The main steam isolation valves and the inboard drain valves were already closed.

At 5:10 p.m., suppression pool level reached 18-feet 6-inches, requiring entry into PEI-T23, (Containment Control). The rise in suppression pool level was expected due to RCIC and SRV operation. At 7:08 p.m., indications of high hydrogen concentrations in the drywell and containment were received. Hydrogen analyzer "A" was reading 2.5 percent hydrogen concentration in the drywell head and analyzer "B" was reading 1.5 percent concentration in the containment dome. As a result, PEI-M51/56, (Drywell and Containment Hydrogen Control), was entered and the hydrogen igniters started. Subsequent samples measured actual hydrogen concentrations of 0.03 percent in the drywell and 0.05 percent in containment. The apparent cause for the initial indications of high hydrogen were hydrogen analyzer equipment problems and did not appear to be related to the flooding. At 8:15 p.m., shutdown cooling was established and the plant was subsequently placed in cold shutdown.

Though safety systems were not affected, important nonsafety-related systems, including the instrument air compressors and the recirculation pumps, were impacted. The operators took actions to secure or provide alternate cooling methods to equipment to prevent them from overheating and getting damaged. Due to prompt and effective action, no significant equipment problems were caused by the loss of SW. The operators referenced all of the appropriate ONIs and integrated operating instructions (IOIs) in responding to the event.

The overall adequacy of procedures and effectiveness of operator actions to mitigate the consequences of the event were excellent. One problem did occur due to operator misinterpretation of a step in procedure ONI-P41. This resulted in the premature securing of both condenser hotwell pumps. The resultant loss of condensate flow resulted in steam jet air ejector exhaust steam being discharged into the offgas system without being condensed. As a result, a potential for damage to the charcoal beds existed. In addition to the impact on the offgas system, operators in the field noted minor water hammer transients due to the loss of condensate flow. Based on post-event walkdowns, no significant damage to plant equipment was noted.

As discussed above, three PEIs were entered during the event. Based on discussions with plant operators and review of the PEIs, no deficiencies were identified in the effectiveness of the PEIs to guide the operators in keeping the reactor vessel and containment in a safe condition during the event.

Based on review of this event, the team determined that operator response to this event was prompt, effective, and in accordance with plant procedures. The operators quickly evaluated the indications and took prompt action to place the plant in a safe condition. Specific strengths included the following:

- Good communications and teamwork between operators in the field and in the control room enabled the shift supervisor to properly evaluate and deal with the event.

- The operators were proactive in responding to changing plant conditions, as reflected in early use of the RCIC system in anticipation of the loss of feed and condensate, and the placement of both trains of RHR in suppression pool cooling mode in anticipation of temperature increases due to RCIC and SRV operation.

- Good use of procedures assisted in the prioritization and combating of individual equipment problems.

The team concluded that the operators safely responded in an excellent manner to the event and that their actions were indicative of a strong knowledge of plant systems and plant operating procedures.

3.0 Event Classification and Reporting

The licensee classified the event as an Alert in accordance with emergency action level initiating condition K.II.1, accident or hazard which indicates an actual or potential substantial degradation in the level of plant safety. The emergency plan specified that if an event causes visible damage to, or in the judgment of the emergency coordinator (in this case, the shift supervisor) threatens safe shutdown equipment, an Alert be declared. Based on the shift supervisors observation of the rupture initiation, and numerous reports of water intrusion into various plant areas, the Alert was declared at 3:35 p.m. Upon Alert declaration, the Technical Support Center (TSC) and the Operations Support Center (OSC) were activated. Upon being notified of substantial water ingress into the control complex 599-foot elevation and reports of water in the OSC and water restricting access to the TSC, the emergency coordinator selected alternate facilities. The OSC was relocated to the rear access facility and the TSC was transferred to the Emergency Operation Facility in the Training and Education Center (TEC) within the owner controlled area, approximately 1.5-miles from the plant. Subsequently, the OSC and TSC were declared operational at 4:00 p.m. and 4:30 p.m. respectively. The Alert was terminated at 1:05 a.m. on March 27, 1993, upon stabilization of plant conditions and establishment of a recovery plan.

The team reviewed the specific circumstances surrounding the event and discussed the event with plant operators and other licensee personnel, including the licensee emergency planning staff. Based on this review, the team concluded that declaration of an Alert was appropriate, the decision to stay in the Alert for 9.5-hours was conservative, and that required notifications were made in a timely manner. The licensee held a critique of Emergency Preparedness during the event and the results will be reviewed in a later inspection.

4.0 Inspection Results

4.1 Service Water Piping

4.1.1 Performance History and Maintenance

Since 1985, there have been five unrelated failures in the SW system. An inspection of the SW piping had never been performed because the SW system was constantly in use, including during outages. The five failures consisted of:

a. Three failures occurred on the 6-inch SW strainer blowdown line. These were: a leaking joint, a cracked section due to the January 31, 1986, earthquake, and a cracked section apparently caused by careless work during a previous repair effort.

b. Three cracks on the 54-inch main header leading out of the SW pump house. These were the result of the pipe being struck by a backhoe during previous careless repair work on the 6-inch line.

c. A leaking joint on the 42-inch line south of the service building due to inadequate preparation of the joint during original installation.

Preliminary inspection of the SW pipe adjacent to the failed location and the portions of pipe removed during excavation indicated that the system had not suffered general degradation.

4.1.2 Material Condition of Affected Piping

The failure analysis effort was hampered by the fact that substantial portions of the failed area were lost at the time of the rupture. Pieces from the failed area were broken off and washed away during the flooding that followed the rupture. Although the licensee recovered numerous pieces from the ground surrounding the eruption site, it appeared that many had been lost in the numerous storm drains in the area. However, the team ascertained that the cause was local to the failure location and was not the result of general system wide degradation.

Smoothly worn surfaces caused by erosion of the fiberglass, at what appeared to be the initial failure location, indicated that the pipe leaked for a significant time period prior to the catastrophic failure. The failure location was through a patch on the inside of the pipe. The patch was a single layer of fiberglass approximately 5-inches wide and of some undeterminate length (possibly around the full inside circumference of the pipe). The edge of the patch was not smoothly tapered into the base material. This would tend to create a stress riser on the inside of the pipe. Several other smaller patches were seen on the inside and outside of the accessibl. portions of the pipe. Based on the materials, workmanship, and lack of any damage under the patches, it appeared that these patches were performed by the pipe manufacturer to repair areas containing voids in the resin. No pipe joint was involved in the failure.

The team's investigation considered the following as a possible contributing cause to the pipe failure. The affected pipe crossed the location of the edge of the original foundation excavation. This was a transition from undisturbed natural soil into deep, compacted, clay backfill. This difference in soil compaction may have resulted in differential settlement which could have imposed a bending stress at the break location. This stress may have imposed an increased load on an already weakened location, which by itself may have been within allowable stress levels for the material. After removal of the broken sections of pipe, the licensee compared the elevations for the remaining pipe ends and determined that the section of pipe remaining in the fill material was about 5-inches lower than the pipe remaining in the natural material. The difference in elevations supports the differential settlement theory; however, this may also represent original construction elevations.

The team postulated the following sequence of events leading to the rupture. Assuming a leak existed for months or longer, the water from the small leak would probably have been carried away by the free draining sand backfill placed around the pipe. Over time the leak increased, as evidenced by a smoothly eroded surface around the hole at the failure location. As the size of the eroding hole increased, stresses on the pipe increased. Eventually, local tearing rapidly increased the size of the leak. This caused water to come to the surface because it could no longer be carried away by the sand. As clay overburden and sand bedding material were being carried away, the flow increased causing more soil erosion. When the licensee noticed a drop in SW pressure, a fourth SW pump was put in service to increase pressure. This increase in pressure may have caused the pipe break size to increase or possibly caused the complete separation. Recognizing the failure of the SW pipe, the licensee shut down all the pumps in the SW system. The pressure of the escaping water probably initially supported the overburden. When the pumps were shut off, the support was lost for the undermined soil and asphalt paving above the pipe. This resulted in it caving-in. The cave-in caused two secondary pipe breaks to occur; one approximately 13-feet and one approximately 16-feet on either side of the original failure.

The local failure mechanism concept appears to be supported by the absence of widespread cracking which would result from system wide distress during service. Visual examination of exposed portions of the pipe revealed no other significant degradation or damage. There was some shallow cracking at the top inside of the pipe. This is a common condition in buried fiberglass pipes and is not a serious condition.

Fiberglass pipe is a brittle material with roughly the same ductility as cast iron. As a result, it is susceptible to cracking, instead of bending, in a limited area as a result of impact or a local overstress condition. Local damage can exist which would result in a failure, such as the one experienced, even though there is no overall system distress. Because this material is susceptible to isolated cracking at random locations, it is not possible to judge the overall system condition based upon a limited inspection.

The local damage causing the initial leak may have been the result of one of several causes, including:

a. Impact damage during construction
b. Contaminated backfill containing sharp debris
c. Service induced damage resulting from debris in the pipe
d. Failure of the patch

4.2 Flooding

4.2.1 Amount of Water and Flood Path

Water flooded the ground surface surrounding the SW pipe break and entered the plant primarily through electrical manhole (EM) number 1 at the northwest corner of the radwaste building. EM 1 was covered with concrete plugs that had gaps of 2 to 3-inches. These gaps readily allowed water to flow into the manhole.

Discharge from the break ceased when the SW pumps were shutoff approximately 16-minutes after the start of the fourth SW pump. (The fourth SW pump was started at about the same time of the pipe break.) The licensee estimated that the outflow rate during the 16-minutes approached 89,900 gpm for a total leakage volume of approximately 1.71 million gallons.

Approximately five percent of the total leakage (85,000 gallons) entered the plant and reached the following plant locations by way of EM 1 and by flowing under various roll-up and access doors on the west side of the plant (Note: all elevations are with respect to sea level, with elevation 620-feet being ground level):

(1) Water and silt on floors of the:
- Control complex at elevations 599-feet, 574-feet, and 564-feet
- Auxiliary building at elevations 620-feet, 599-feet, 574-feet, and 568-feet
- Intermediate building at elevations 620-feet, 599-feet and 574-feet

(2) Water and sand in the turbine power complex at elevation 620-feet, 593-feet and 548-feet.
(3) Water and silt on the floors of the radwaste truckbay at elevation 620-feet.
(4) Water in the offgas building at elevation 620-feet and in it's lower levels.
(5) Water and silt on the floor of the turbine building laydown area.
(6) Some leakage into the water treatment building at ground level.
(7) Water on the floor of the main entrance lobby of the service building.
(8) The emergency service water pump house (ESWPH) floor was wet and covered with silt.
(9) The SW pump house lower level had water and silt resulting from a failure of a SW screen wash pump casing. Also, water and silt were noted in the electrical mezzanine floor of the SW pump house.

(10) Water in the Unit 2 auxiliary building at elevation 568-feet.

The external surface water paths included (see Figure 2 for a map of the flooded areas):

South: The water ran south past the diesel generator fuel storage tanks to all low points in the yard and into storm drains. The water ran past the service building annex approaching the Unit 2 turbine building laydown area.

North: The water ran north up the road area near the maintenance building. The water also came in contact with the water treatment building and turbine building to the north.

West: The water ran west past the security fence, northwest to the lake and southwest into and past the primary access control point (PACP).

East: The water ran east and came into contact with the offgas, turbine power complex (TPC), auxiliary, radwaste, diesel generator, and service buildings.

4.2.2 Design of the Underdrain System

The underdrain system beneath the plant was constructed to prevent excessive uplift pressures from developing beneath the buildings as a result of an extremely high natural ground water table. The system consisted of a porous concrete blanket with a circuit of 12-inch diameter porous concrete pipes beneath the buildings to collect and convey the ground water to manholes, and two systems to remove the water from the manholes and discharge the water to the lake.

One discharge system used pumps located in the manholes, and the other used higher elevation pipes to convey the water by gravity to the lake. The pumped discharge system was designed to convey water through the porous concrete blanket and pipes to collection manholes. The water was then discharged from the manholes by submersible pumps, maintaining the water level between elevation 566 and 568-feet.

The gravity discharge system, which consisted of 36-inch to 48-inch pipes connecting the manholes, was some 20 to 25-feet above the underdrain blanket. It provided an alternate flow path for drainage in the event of a complete failure of all the pumps. This system ensured that the water level never exceeded elevation 590-feet. It incorporated a gravity outfall and was designed to handle a total flow of 60,000 gpm for two units, 30,000 gpm for each.

4.2.3 Water Level Flood Design

The site grading and storm drainage system were designed to preclude subjecting seismic category I structures to water levels greater than 6-inches above plant grade of elevation 620-feet. Assuming the worst case (i.e., complete blockage of the site storm drainage system and using peak discharge from the most intense hour of the probable maximum precipitation (PMP) the plant site was graded so that overland drainage would occur away from the site buildings and the resulting ponding elevation of 620-feet 5-inches would have no adverse affect upon safety class equipment because the floors at plant grade are set at elevation 620-feet 6-inches.

Portions of safety class structures located below finished grade were protected on their outside surfaces by a continuous waterproofing membrane. Also, waterstops were provided at construction joints. Additionally, flood protection for safety class components, equipment and systems located below grade were provided with a floor drain system that would handle leaks of lesser relative magnitude.

The design criteria for ensuring the prevention of damage to safety-related equipment by internal flooding caused by a pipe rupture in a moderate energy system, such as the SW system, were:

a) Plant layout uses separation of seismic category I and non-seismic category components by locating them, where possible, in separate buildings.
b) Emergency core cooling system (ECCS) equipment was located in separate, water tight compartments.
c) Small leaks were handled by the floor drain system.

Prevention of internal flooding damage had been analyzed in the Updated Safety Analysis Report (USAR) and conformance to the analysis is discussed later.

4.2.4 Conformance with the Updated Safety Analysis Report (USAR) Assumed Magnitude and Path

The USAR design basis accidents (DBAs) assumed for the underdrain system were: (1) a yard break in the circulating water pipe outside the plant near the steam tunnel and auxiliary building, or (2) failed expansion joints occurring inside the turbine building through flow from a fracture in the building base mat.

The underdrain system (including the pumped discharge subsystem and the gravity discharge subsystem) was designed to handle the total volume of water released during the DBAs and maintain the underground water level below elevation 590-feet.

The paths that the water took during the SW pipe break were not specifically considered in the USAR underdrain system analysis; however, it was bounded by both of the underdrain system design basis floods. The internal and external flow resulting from the 30-inch SW line break did not challenge the capacity of the underdrain system.

(1) External

The outflow of the SW break ran off following the slope of the adjacent ground surface and either slowly seeped into the ground, was collected by the catch basins located throughout the site for the purpose of collecting storm runoff, or ran into Lake Erie at the northwest corner of the site. The ground seepage rate was extremely low due to the 3-feet of impervious fill placed over the site to reduce infiltration at the ground surface. The resulting inflow from the seepage into the underdrain system would be much lower than for the design basis in-ground circulating water (CW) system pipe break. Flow into the underdrain system from the underdrain system manholes was not a concern since all the manholes were closed as required. Flow resulting from seepage, and any flow through the gasketed manholes, was disposed of by the underdrain system backup pumps which were in operation.

(2) Internal

A sizable portion of the water that flowed into the plant entered through EM 1. Four sets of electrical penetrations were routed through EM 1 at the northwest corner of the radwaste building and terminated at the ceiling of control complex elevation 599-feet. Water also entered the plant by flowing under various roll-up and access doors on the west side of the plant.

The vast majority of the water that entered the plant was collected in the radwaste system collection tanks through the plant drain system.

Corrective action taken after the December 1991 CW system pipe break precluded flow into or out of the plant by the underdrain system piezometer tubes. Plant procedures were changed to require that the piezometer tube covers be replaced after use of the tubes.

4.2.5 Effects of Flooding

The flooding caused by failure of yard piping was found to result in conditions that do not jeopardize safe plant shutdown or adversely affect operation of safe shutdown systems.

Auxiliary Building
A maximum of 5-inches of standing water was reported on elevation 568-feet. Water depths of less than 20-inches on the lower elevations of the auxiliary building would not compromise the operability of safety-related components.

An indeterminate level of flooding on elevation 599-feet resulted in leakage into the high pressure core spray (HPCS) pump room through the ceiling concrete hatch plugs. This ingress resulted in water dripping on the HPCS pump motor. The motor was subsequently inspected and meggered and no abnormal conditions were found.

Intermediate Building
Flooding of less than 6-inches in the lowest level of the intermediate building would not threaten the operation of any safety-related equipment. In the case of the SW pipe break, water levels of up to 5-inches were reported on

elevation 574-feet. Due to the heavy silt content of the flood water, the drains appeared to have backed up.

Control Complex (CC)
Equipment required for safe shutdown or for maintaining control room habitability was located 6-inches above elevation 574-feet. In the case of the SW pipe break, water level of up to 5-inches were reported on this elevation. The source for leakage into the CC was electrical manhole (EM) 1. Four sets of electrical penetrations were routed through EM 1 at the northwest corner of the radwaste building and terminated at the CC 599-foot elevation ceiling. Junction boxes (JB) 12503 (Unit 1, Division 1 and 3 cabling) and JB 2473 (Unit 2, Division 3 Cabling) as well as open conduit penetrations for Unit 1, Division 2 cabling and Unit 2, Division 2 cabling were the major sources of water intrusion at the CC 599-foot elevation. Temporary plugs existed on open conduits but they were forced out by the head of water from the flooding. The water on elevation 599-feet leaked through floor plugs at that elevation and flowed through the southwest stairway onto elevation 574-feet.

Emergency Service Water Pump House (ESWPH)
Water entered the ESWPH as a result of flooding in the yard area through conduits at the southwest corner of the pump house. The water source for this path was through EM 1 at the northwest corner of the radwaste building. The ESWPH floor was wet or covered with silt over most of the area. Additionally, the motor fire pump controller was wet on the surface but was not damaged. Water was also found in an inoperable Unit 2, Division 2 motor control center (MCC). No safety-related components were affected.

Turbine Power Complex (TPC)
The turbine power complex elevation 593-feet had water entry from three empty 6-inch penetrations originally slated for fire protection piping. During the flood, water ran on grade level between the interbus transformers and the TPC south wall and was able to flow into the penetrations. Along with water, Grade A fill (sand) also came out of the three penetrations.

Water also entered the TPC at elevation 593-feet from a penetration that was connected to EM 8. Water ran down the wall and fell on to fire damper 1M36F571 and subsequently fell on condensate filter control panel 1H51P014.

Flooding in Other Plant Buildings
The offgas and radwaste buildings, the SW pump house, and other detached structures contained no components essential to safe shutdown. No flood protection was required for any of these areas.

4.3 Equipment Problems

As stated earlier, no safety-related equipment failures resulted from the SW pipe break or from the subsequent flooding. However, various nonsafety-related equipment problems were experienced during the event:

The glycol skid in the offgas building had water flowing on it that caused erratic operation and instrument indication problems. A work order was issued to investigate for possible damage.

The hydrogen analyzers generated what appear to be false elevated readings. As stated elsewhere, these high readings do not appear to be related to the flooding. The hydrogen analyzers were scheduled to be recalibrated.

As discussed elsewhere, the offgas system charcoal beds may have been damaged due to the discharging of steam into the offgas system.

The south SW screen wash pump upper casing split during the event. The root cause of the casing failure was still under investigation.

The "A" control rod drive (CRD) drive pump experienced minor cavitation/waterhammer due to loss of suction during the event.

4.4 Radiological Releases

No radiological releases occurred as a direct result of the SW pipe break and subsequent flooding. The 85,000 gallons of water estimated to have leaked into various site buildings was contained within those buildings. Any potentially contaminated water was sent to the radwaste system collection tanks through the floor drains. The licensee took environmental samples at a number of locations, including the major stream, northwest discharge drainage, minor stream skimmer, and at the sanitary sewer lift station, all with no detectable activity. Sediment samples from the northwest impoundment and the Unit 2 intermediate building sump also resulted in no measurable levels of activity being detected.

One unmonitored gaseous radiological release did occur during the event. The release occurred on March 27, 1993, and was the result of the "B" auxiliary boiler becoming contaminated. When the plant shut down, it was necessary to provide an alternate source of heating steam. This was accomplished by use of one of the two auxiliary boilers. When the licensee started the auxiliary boiler, the boiler was initially vented to atmosphere. This provided a vent path for the contamination to atmosphere, along with steam. The licensee indicated that this was the third such occurrence since October 1992. As of this inspection, the licensee had not been able to determine the cause for the auxiliary boiler becoming contaminated and was continuing their investigation. The initial estimate by the licensee on the amount of the release was a total of 22.25 micro-Curies. This would have resulted in an insignificant exposure at the site boundry.

The team concluded that the gaseous radiological release was minimal and well below regulatory limits.

5.0 Safety Significance

The consequences of the event posed no threat to public health and safety. A minor gaseous radiological release occurred but was not directly attributable to the event. The release was minimal and well below regulatory limits.

Internal plant flooding was limited. The amount of water that entered the plant and the corresponding amount of flooding on various elevations did not reach a level that could affect safety-related equipment and was bounded by the design basis flooding analysis. No significant operational safety parameters were approached or exceeded. Based on the above, the event was not safety significant; however, response to the event required a rapid reactor shutdown, including a manual reactor scram, and the consequent actuation of safety equipment.

6.0 Corrective Actions For the December 1991 Circulating Water Line Break

6.1 Background

On December 22, 1991, the licensee experienced a 36-inch circulating water (CW) system pipe rupture which caused considerable flooding to various buildings. The NRC dispatched an AIT to evaluate that event (reference NRC Inspection Report 50-440/91026(DRS)). In response to that event the licensee took or was evaluating corrective actions to minimize internal flooding.

6.2. Inspection

The team reviewed the corrective action taken by the licensee for the above event. Repair and replacement of the CW pipe, pipe supports, and monitoring activities appeared adequate. Correctiv_ action by the licensee to mitigate the flooding of safety-related equipment and buildings had not been completed. During the previous event, water from the underdrain system piezometer tubes appeared to have leaked into the basement floors of buildings because covers for the tubes were either loose or not installed. During this event, the tubes were all closed and no water entered through this path. Previously some of the water that leaked into the intermediate building 574-foot elevation passed underneath a security door and into a Unit 2 auxiliary building sump. That water was slightly contaminated and was pumped from the sump and eventually off site. The licensee had taken no action to preclude water from passing under the security door into Unit 2; however, they had de-energized and disconnected the sump pump so that the water collected was not pumped out. During this event, the water that flowed under the security door was retained in the building.

Electrical manholes (EMs) were not sealed on the surface and, under flood conditions, water could fill up the EM and flow through electrical conduits. EM 1 was observed to have gaps of 2 to 3-inches by 15-feet. This EM was adjacent to the SW line break and was reported to have approximately 12-inches of flooding at the surface in the area of the manhole. This flooded the EM. The water that leaked into the EM flowed through conduits to various areas of the plant. No degraded equipment was experienced from the flooding, but the intrusion of water was evident by the amount of silt and moisture still present during the inspection. The licensee was evaluating methods of preventing flood waters from entering the manholes.

The emergency service water pump house (ESWPH) conduit banks on the southeast corner were sealed to minimize water intrusion to the ESWPH in the event of flooding of EM 3. During this event EM 1 flooded and directed water through conduits to the ESWPH. These conduits, located on the southwest corner of the ESPWH, were not sealed and allowed water to enter. However, the conduits the licensee had sealed prevented water from penetrating into electrical equipment. The water that was directed into the ESWPH ended up on the floor.

The control complex also experienced water intrusion through conduits from EM 1. Expansion plugs installed at these locations were expelled by the flow of water through the conduits. This caused flooding of approximately 6 to 8-inches at the 599-foot elevation. This location flooded during the previous event because of water entering through these conduits.

The licensee had initiated corrective action documents to seal these conduits, however the time schedule for completion was to be during the fifth operating cycle (1994-1995). At the conclusion of this inspection the licensee was evaluating expediting this schedule.

7.0 Conclusions

After completing the AIT Charter, the team was able to make the following conclusions:

(1) The consequences of the event posed no threat to public health and safety. No significant operational or safety parameters were approached or exceeded.

(2) The pipe rupture is believed to have resulted from a small perforation and leak in the pipe which slowly grew in size due to erosion. Several potential root causes for development of the initial perforation were identified. However, a single root cause could not be determined. The team does believe that the conditions which led to the pipe rupture were localized. The local failure mechanism concept appears to be supported by the absence of widespread cracking which would result from excessive bending or other gross loads during service. Inspection of the limited sections of service water system piping that could be observed by the team indicated that no system wide degradation appeared to have occurred.

(3) The flooding did not effect the function of any safety-related equipment.

(4) The operators safely responded in an excellent manner to the event and their actions were indicative of a strong knowledge of plant systems and procedures.

(5) A minor gaseous radiological release occurred but was not directly attributable to the event. The release was minimal and well below regulatory limits.

(6) Some additional contamination of the plant occurred as a result of the internal flooding. Water passing through existing

contaminated areas and floor drains backing up in lower elevations spread contamination to previously clean areas. Overall, the amount and the extent of contamination were not radiologically significant.

(7) Corrective actions for the December 1991 circulating water pipe break and subsequent flooding had only partiality been implemented and, as a result, areas that were flooded before were flooded again.

8.0 Charter Completion

The team completed the Charter on April 2, 1993, and the AIT was disbanded after discussion with Region III management.

9.0 Exit Interview

The team met with licensee representatives (denoted in Attachment 3) on April 2, 1993, and summarized the purpose, AIT charter items, and findings of the inspection. The team discussed the results of the inspection. The licensee did not identify any proprietary documents or processes reviewed by the team.

ATTACHMENT 3

Personnel Contacted

Centerior Service Company

M. O'Reilly, Senior Attorney

Cleveland Electric Illuminating Company

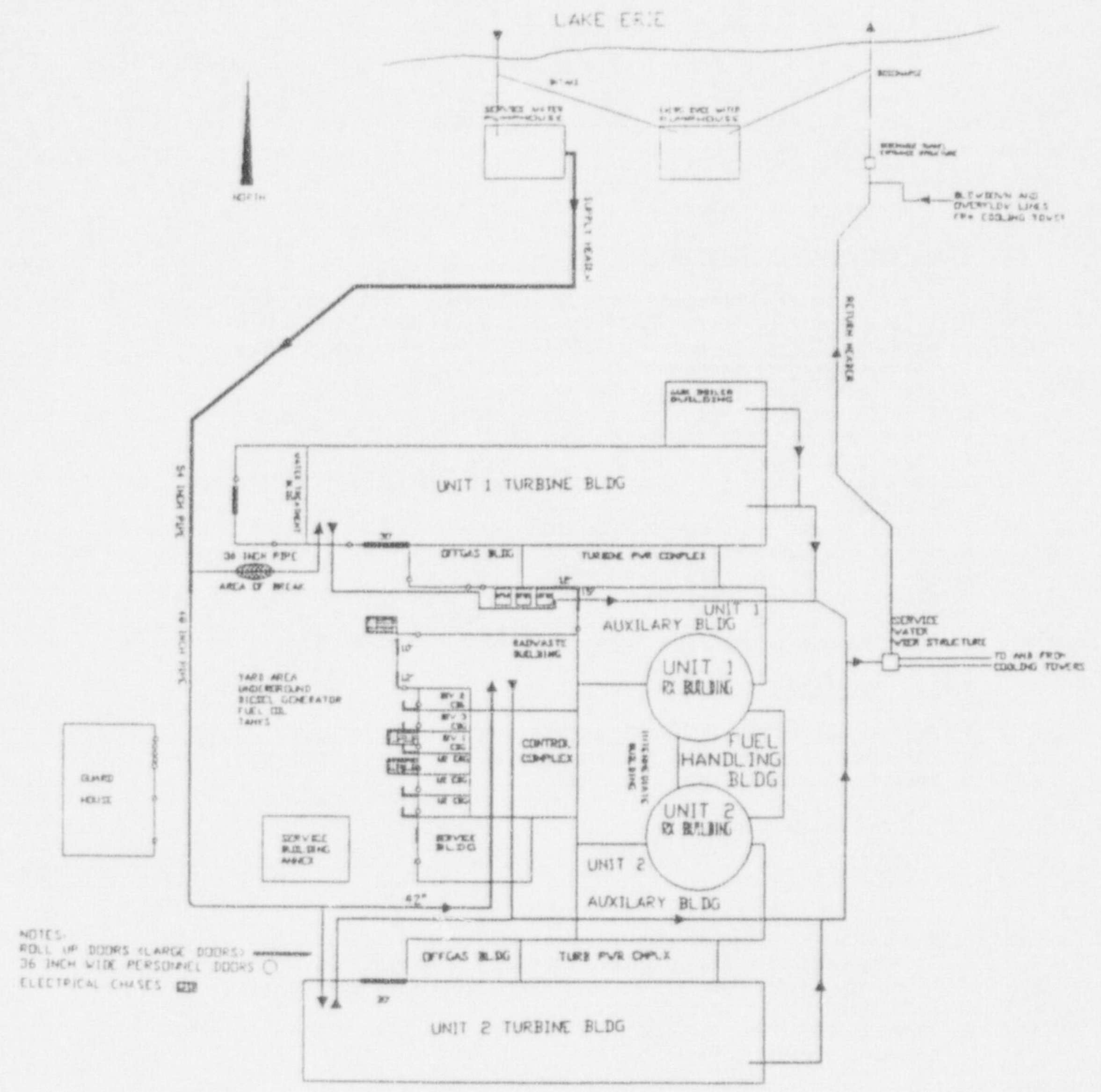
D. Igyarto, General Manager, Perry Nuclear Power Plant (PNPP)
B. Beyer, Director, Perry Administrative Support Department (PASD)
S. Kensicki, Director, Perry Nuclear Engineering Department (PNED)
V. Concel, Manager, Systems Engineering, PNED
J. Eppich, Manager, Mechanical Design, PNED
D. Graneto, Manager, Maintenance Section, PNED
W. Kanda, Manager, Electrical Design, PNED
F. Vanann, MEU Supervisor, PNED
K. Donovan, Manager, Licensing and Compliance, Perry Nuclear Support Department (PNSD)
H. Hegrat, Supervisor, Compliance, PNSD
M. Gymrek, Manager, Operations, PNPP
J. Emley, Licensing Engineering, PNSD
R. Gaston, Compliance Engineer, PNSD
M. Hayner, Licensing Supervising Engineer, PNSD
K. Pech, Manager, Integrated Scheduling and Controls, PNSD

Nuclear Regulatory Commission

T. Martin, Acting Director, Division of Reactor Safety (DRS)
R. Lanksbury, Section Chief, Team Leader
D. Kosloff, Senior Resident Inspector
A. Vegel, Resident Inspector
J. Guzman, Reactor Inspector
J. Strasma, Public Affairs Officer

Other

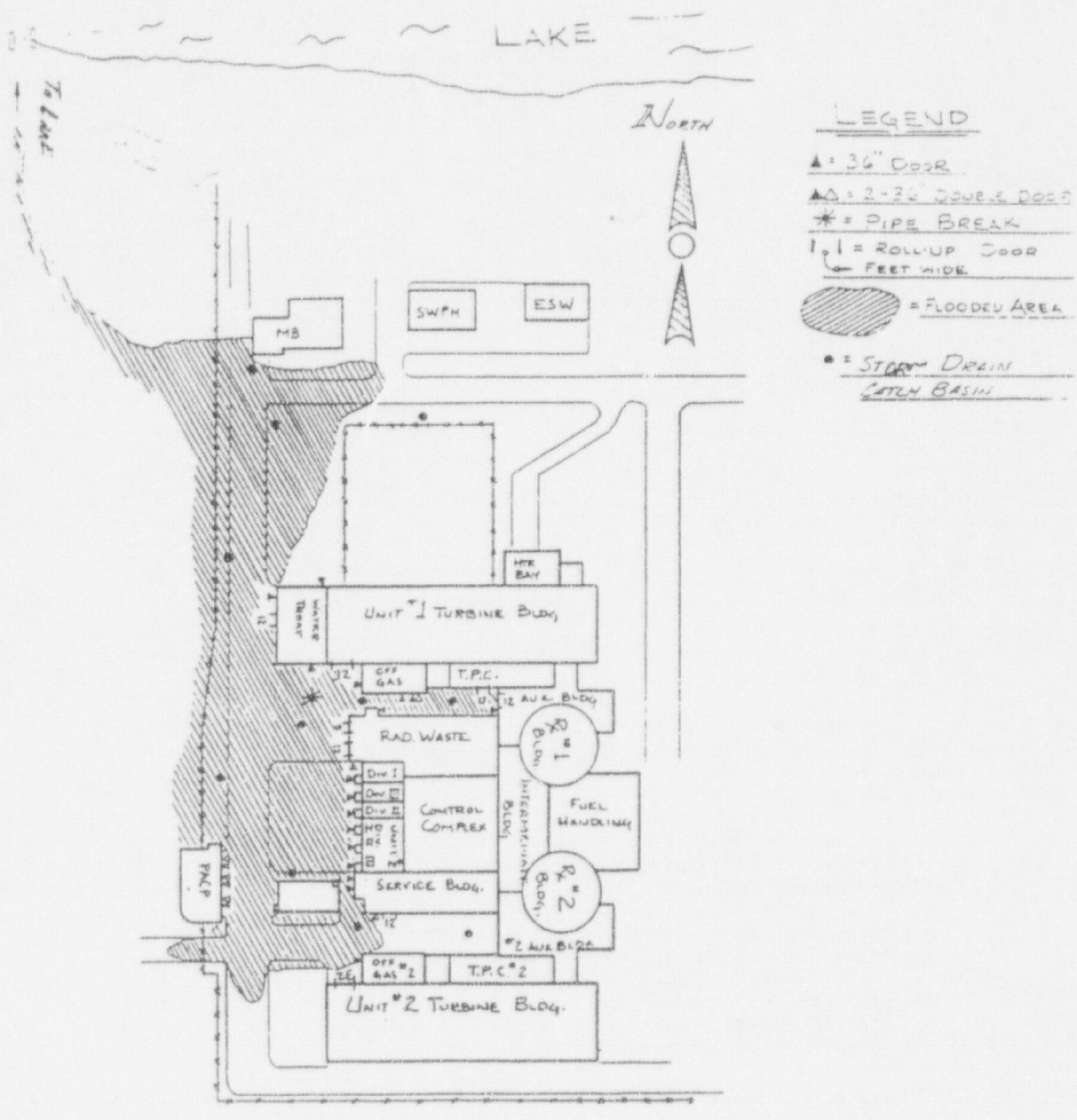
H. Ray Caldwell, Director, Nuclear Activities, Ohio Edison Company
T. Reeves, Radiation Analyst, Ohio Emergency Management Agency
J. Vitellas, Energy Specialist, Ohio Public Utilities Commission
S. Bair, Reporter, Star-Beacon
S. Johnson, Reporter, News Herald
J. Kuehner, Reporter, Plain Dealer



SERVICE WATER SYSTEM PIPING LAYOUT

NO SCALE

FIGURE 1



SERVICE WATER PIPE BREAK FLOOD PATH

NO SCALE

FIGURE 2

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137-5927

ATTACHMENT 1

MAR 3 0 1993

CONFIRMATORY ACTION LETTER

Docket No. 50-440
License No. NPF-58
CAL No. RIII-93-004

Centerior Service Company
ATTN: Mr. R. A. Stratman
Vice President
Nuclear - Perry
c/o The Cleveland Electric
Illuminating Company
10 Center Road
Perry, OH 44081

Dear Mr. Stratman:

SUBJECT: CONFIRMATORY ACTION LETTER

Pursuant to a telephone conversation between Mr. T. O. Martin of my staff and you on March 30, 1993, related to the service water line rupture which occurred on March 26, 1993, it is our understanding that you will take the following actions:

1. Conduct an investigation to determine the cause of the service water line failure and to evaluate the decision making and communications associated with the event.

2. Maintain documentary evidence of your investigation effort and make this available to the Augmented Inspection Team.

3. Evaluate the service water line rupture in light of past service water and circulating water line (fiber glass lines) failures to determine if additional actions are necessary.

4. Provide within 30 days to NRC Region III a documented evaluation of the above issues including corrective actions you have taken or plan to take.

None of the actions specified herein should be construed to take precedence over actions which you feel necessary to ensure plant and personnel safety.

CONFIRMATORY ACTION LETTER

MAR 3 0 1993

CONFIRMATORY ACTION LETTER

Centerior Service Company 2

Pursuant to Section 182 of the Atomic Energy Act, 42 U.S.C. 2232, and 10 CFR 2.204, you are required to:

1. Notify me immediately if your understanding differs from that set forth above,

2. Notify me if for any reason you cannot complete the actions within the specified schedule and advise me in writing of your modified schedule in advance of the change, and

3. Notify me in writing when you have completed the actions addressed in this Confirmatory Action Letter.

Issuance of this Confirmatory Action Letter does not preclude issuance of an order formalizing the above commitments or requiring other actions on the part of the licensee. Nor does it preclude the NRC from taking enforcement action for violations of NRC requirements that may have prompted the issuance of this letter. In addition, failure to take the actions addressed in this Confirmatory Action Letter may result in enforcement action.

The responses directed by this letter are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96-511.

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

Sincerely,

A. Bert Davis

A. Bert Davis
Regional Administrator

See Attached Distribution

MAR 3 0 1993

CONFIRMATORY ACTION LETTER

Centerior Service Company 3

Distribution

cc:
F. R. Stead, Director, Nuclear
Support Department
D. P. Igyarto, General Manager,
Perry Nuclear Power Plant
K. P. Donovan, Manager,
Licensing and Compliance Section
S. F. Kensicki, Director, Perry
Nuclear Engineering Dept.
H. Ray Caldwell, General
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L. R. Greger, RIII
R. D. Lanksbury, RIII

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
799 ROOSEVELT ROAD
GLEN ELLYN, ILLINOIS 60137-5927

ATTACHMENT 2

MAR 2 7 1993

MEMORANDUM FOR: Roger D. Lanksbury, Team Leader, Perry Augmented Inspection Team (AIT)

FROM: Edward G. Greenman, Director, Division of Reactor Projects

SUBJECT: DRAFT AIT CHARTER - PERRY SERVICE WATER FIBERGLASS PIPE BREAK

Enclosed for your implementation is the Charter developed for the inspection of the events associated with the Perry service water line break which occurred on March 26, 1993. This Charter was prepared in accordance with the NRC Incident Investigation Manual and the Manual Chapter 0325 AIT implementing procedure, and is based on the discussions you had with Region III personnel on March 27, 1993. As stated, the objectives of the AIT are to communicate the facts surrounding this event to regional and headquarters management, to identify and communicate any generic safety concerns related to this event to regional and headquarters management, and to document the findings and conclusions of the onsite inspection.

If you have any questions regarding these objectives or the enclosed Charter, please do not hesitate to contact either Tom Martin or myself.

Edward G. Greenman

Edward G. Greenman, Director
Division of Reactor Projects

Enclosure: Draft AIT Charter

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PERRY SERVICE WATER LINE BREAK

DRAFT AUGMENTED INSPECTION TEAM (AIT) CHARTER

INVESTIGATE:

1. The break of the 30" fiberglass service water line and subsequent flooding.

2. Probable root cause(s).

3. Performance history and maintenance on service water piping.

4. Operator response to the event, including use of the Plant Emergency Instructions (PEIs).

5. Effects of flooding.

6. Event classification and reporting.

7. Corrective actions.

8. Conclusions.

QUESTIONS FOR PERRY AIT:

1. The break of the 30" fiberglass service water line and subsequent flooding (3/26/93).

   1.1 What was the sequence of events?

   1.2 How much water was pumped from the break and where did it go?

   1.3 What was the flood path (internal and external to the plant)?

   1.4 Did the flood path conform to the USAR assumed flood paths and magnitude?

   1.5 What was the safety significance of the event? (Include any PRA insights, to the extent practicable. Analyze loads on service water system to determine the affect of its loss on the safe shutdown of the plant and maintenance in a safe shutdown condition, including spent fuel pool cooling.)

   1.6 Were the licensee's corrective actions from the 12/22/91 circulating water event effective in minimizing the consequences of this event?

2. Probable root cause(s).

   2.1 What was the root cause of the event?

3. Performance history and maintenance on service water piping.

   3.1 What is the material condition of the affected piping?

   3.2 Has there been any history of leakage in the affected line or any related maintenance activities?

   3.3 Were there any on-going activities that could have been precursors to the event?

   3.4 Has there been any reported damage to the piping during either construction or operation?

4. Operator response to the event, including use of the Plant Emergency Instructions (PEIs).

   4.1 What operator actions were taken during the event? Were they appropriate?

5. Affects of flooding.

   5.1 Identify all affected equipment.

      5.1.1 Electrical: cables, switch gear, MCC, etc

      5.1.2 Mechanical: pumps, valves, etc.

      5.1.3 Specifically review water ingress to HPCS, RHR, RCIC, LPCS rooms and potential for affecting the operation of these pumps.

   5.2 Identify the extent of water damage.

   5.3 Radiological consequences.

      5.3.1 Extent of contamination from floor drain backup.

      5.3.2 Offsite releases, if any.

6. Event classification and reporting.

   6.1 Was the event properly classified and were required notifications made in a timely manner?

7. Corrective actions and evaluations.

   7.1 What are the licensee's short term and long term corrective actions and evaluations?

      7.1.1 Service water piping

7.1.2 Electrical components such as cable trays, switchgear, MCC's

7.1.3 Effected mechanical components

7.1.4 Radiological consequences, if any

8. Conclusions.

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11. ABSTRACT (200 words or less)

Sixteen operational events that affected sixteen commercial light-water reactors during 1993 and that are considered to be precursors to potential severe core damage are described. All these events had conditional probabilities of subsequent severe core damage greater than or equal to 1.0×10^{-6}. These events were identified by first computer-screening the 1993 licensee event reports from commercial light-water reactors to identify those that could potentially be precursors. Candidate precursors were then selected and evaluated in a process similar to that used in previous assessments. Selected events underwent engineering evaluation that identified, analyzed, and documented the precursors. Other events designated by the Nuclear Regulato Commission (NRC) also underwent a similar evaluation. Finally, documented precursor were submitted for review by licensees and NRC headquarters and regional offices to ensure the plant design and its response to the precursor were correctly characterized. This study is a continuation of earlier work, which evaluated 1969-1981 and 1984-1992 events. The report discusses the general rationale for this study, the selection and documentation of events as precursors, and the estimation of conditional probabilities of subsequent severe core damage for events. This document is bound in two volumes: Volume 19 contains the main report and Appendices A-D; Volume 20 contains Appendices E and F.

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