ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
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Attachment:	Supplemental Information

EXECUTIVE SUMMARY

Washington Nuclear Project-2
NRC Inspection Report 50-397/98-15

During the weeks of July 13 and July 27, 1998, the NRC conducted the onsite portion of an engineering team inspection. The team inspection included a review of the design and licensing basis for the high pressure core spray system and associated support systems and a review of the fire protection program.

- The team found that the design and testing of the high pressure core spray system was generally consistent with applicable licensing, design, and operations documents (Section E1).

- The high pressure core spray pump had adequate available net positive suction head. The team found that the high pressure core spray system valves were capable of performing their functions under accident conditions (Sections E1.1.1 and E2.2).

- Design control errors were identified that did not affect equipment operability. The Mode 4 and 5 technical specification surveillance requirement acceptance criterion for condensate storage tank level did not assure the Technical Specification Bases commitment to maintain 135,000 gallons reserve in the condensate storage tank. The technical specification allowable value for reactor vessel water Level 1 in the emergency core cooling system instrumentation table was not correctly derived from the analytic limit for Level 1 in that it did not include sufficient margin for post-accident environmental effects. These errors were determined to be examples of a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," (Sections E1.1.1 and E1.2).

- The licensee had developed a data base that captured the relationship between calculations, so that they could identify needed calculation revisions. When a calculation was revised, the data base was used to identify all of the other calculations that were potentially impacted by the revision. This data base relied on calculation cross references; however, these cross references were not always accurate or complete for older calculations (Sections E1.1.1, E1.3.1 and E8.5).

- Based on a sample of six modification packages, recent design modification packages were correctly prepared in accordance with the current procedures. The plant modification requests addressed all relevant design and safety issues and effectively verified the design changes by post-modification testing. The current format for a modification package was clear and easy to understand (Sections E1.1.2, E1.3.2, and F2).

- In violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," procedures were not always adequately followed or prescribed. Category 1 and 2 post-accident monitoring instruments were not all identified on the main control panel. The temperature assumptions in site short-circuit calculations were not adequately verified to ensure they were representative of actual room temperatures. In addition, the licensee had not identified and accounted for all outstanding calculation

modification records, which could affect the results/conclusions of the electrical system load tally (Sections E1.2, E1.3.1 and E8.5).

- The installed instrumentation and controls met high pressure core spray system logic requirements. The majority of the high pressure core spray controls and instrumentation were installed in conformance with good human factors practices, and the licensee routinely trained the operators regarding the availability and use of particular instruments during accidents. High pressure core spray instrument setpoint channel check and calibration procedures were adequate to ensure safe and reliable operation, and the procedures were well written and had an adequate level of detail (Sections E1.2 and E2.5).

- The licensee responded to the team's findings with a strong safety focus and effectively identified additional examples of issues identified by the team related to testing the Division 2 battery and consideration of post-accident environment effects in the setpoint of reactor vessel Level 1 (Sections E1.2 and E2.6).

- The electrical distribution system for the high pressure core spray system was generally well designed (Section E1.3.1).

- The licensee had not appropriately assessed the significance of some breaker coordination errors in the dc system and, as a result, did not promptly correct these design deficiencies. This was a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," (Section E1.3.1).

- Based on the area walkdowns, the high pressure core spray and high pressure core spray standby service water system configurations were consistent with the design basis. The plant reflects the licensee's apparent attention to housekeeping. The team did not observe any improperly stored material or unsecured temporary equipment (Sections E2.1 and F3).

- One unresolved item was identified concerning establishment of appropriate leak testing for liquid secondary containment bypass valves. This matter is unresolved pending NRC review of the calculation method for evaluating the consequences of leakage from the liquid bypass isolation valves (Section E2.3).

- The thermal performance test results for the high pressure core spray standby service water system demonstrated that the system was operable. However, the Division 3 Diesel Generator cooler thermal performance test acceptance criterion did not assure acceptable thermal performance for all allowed high pressure core spray standby service water system flows in violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control" (Section E2.4).

- The licensee had not fully implemented a new technical specification requirement and, as a result, inappropriately credited a battery performance test for a battery service test. The team identified the issue as it related to the Division 3 battery. During followup of the team's findings, the licensee identified a similar condition for the Divisions 1 and 2 Batteries. This was significant because the previous service test had expired for the

Division 2 battery, which was in violation of Technical Specification 3.0.2. This required a notice of enforcement discretion to allow continued operation (Section E2.6).

- The fire protection program was effectively implemented. Fire equipment was being properly maintained, upgraded, and tested at the required frequencies. The fire brigade was properly trained and qualified to perform fire fighting, and the annual medical examination requirement was being met. The fire protection program procedures were comprehensive in detailing the requirements for control of transient combustibles, barrier impairments, and control of ignition sources. With respect to the fire protection program, the licensee's audit and corrective action processes were effective. Several strengths identified in the 1997 audit by the licensee were confirmed by the team during this inspection, especially fire personnel knowledge and skill, and excellent material condition of the fire fighting equipment (Sections F2, F3 and F7).

Table of Contents

Report Details

Inspection Objectives

This inspection was performed in accordance with two core inspection procedures: "Safety System Engineering Inspection," (93809) and "Fire Protection," (64704). The team reviewed design and licensing documentation for the high pressure core spray (HPCS) system. This system was selected because of its relatively high risk significance. In addition, the team reviewed the design basis documentation for support systems such as HPCS standby service water and associated portions of the electrical distribution system. The team also evaluated implementation of the fire protection program.

III. Engineering

E1 Conduct of Engineering (93809)

E1.1 HPCS Mechanical System Design

E1.1.1 HPCS Mechanical Design Capability

a. Inspection Scope

The team reviewed various HPCS system calculations and compared them to the available licensing, design, and operations documents related to the capability of the HPCS system to supply required flow from either the suppression pool or the condensate storage tank (CST). The team also evaluated the capacity of the CST.

b. Observations and Findings

HPCS System Performance

The team found that the HPCS system was capable of providing the required flow to the reactor pressure vessel under accident conditions as specified in Final Safety Analysis Report (FSAR) Figure 6.3-1, "Head Versus High Pressure Core Spray Flow Used in the LOCA Analysis," and that the value for the technical specification surveillance requirement acceptance criterion for HPCS flow was appropriate. The team also confirmed that HPCS system performance was consistent with the design basis documents provided to a vendor for performance of the emergency core cooling analysis.

Available HPCS Pump Net Positive Suction Head (NPSH)

The team found that the HPCS pump would be provided with adequate available NPSH from both the CST source and the suppression pool source under accident conditions.

The HPCS System design included provisions to automatically transfer the HPCS pump suction supply from the CSTs to the suppression pool in the event of a pipe break in the

non-seismic portion of the CST suction piping outside the Reactor Building. Calculation 5.19.13, "Sizing of HPCS Emergency Water Volume," Revision 5, was performed to verify that, in the event of a pipe break in the non-seismic portion of the CST suction piping outside the reactor building, the HPCS pump suction would transfer prior to air being drawn into the pump suction. This calculation was revised by CMR-94-1160 dated December 19, 1994, and CMR-97-0003 dated April 17, 1997. The team's review of this calculation indicated that Page 26 of the calculation determined the NPSH based on a suppression pool temperature of 140º F. The calculation did not include a reference for the 140º F value. The team asked if a reference for the 140º F value was available. The licensee determined that the suppression pool temperature at the time of the transfer had been revised from 140º F to 146º F as a part of the power uprate analysis performed by GE in 1995. During the inspection, the licensee completed an informal calculation and determined that the results of Calculation 5.19.13 were not affected by this error. The team agreed and concluded that the HPCS pump would be provided with adequate NPSH from the CST supply considering a break in the CST supply piping, the most limiting . This condition was found to be the most limiting NPSH for the system, when supplied from the CST.

The licensee initiated PER 298-0963 and stated that the calculation would be revised to add the appropriate references. This failure to update the suppression pool temperature constitutes a violation of minor significance and is not subject to formal enforcement action. While not safety significant, this issue is similar to Unresolved Item 50-397/96024-02, which was previously closed in NRC Inspection Report 50-397/97-18. The team concluded this minor failure provided further support of NRC's conclusion that the licensee's calculation update controls were weak.

The licensee also developed a calculation that demonstrated that the HPCS pump would be provided with adequate NPSH from the suppression pool assuming a maximum pool temperature of 204º F, a run out HPCS pump flow of 7175 gallons per minute (gpm), and up to 16.1 feet of head loss across the suction strainers. The team found this calculation to be correct and consistent with the licensee's commitment to Regulatory Guide 1.1, "Net Positive Suction Head For Emergency Core Cooling and Containment Heat Removal System Pumps," Revision 0.

Available CST Capacity

The team found that the CSTs were sized to provide an adequate water supply to the HPCS system under accident conditions. However, the operating level requirements in the technical specifications did not assure operation at design basis capacity in some modes.

Technical Specification Surveillance Requirement 3.5.2.2 required that the CST water level be maintained above 13.25 feet in a single tank or above 7.6 feet in each tank if the suppression pool level was below its minimum level. This surveillance requirement was only applicable during plant Modes 4 and 5. The associated Technical Specification Bases, Section 3.5.2, "ECCS - Shutdown," stated that these levels were equivalent to 135,000 gallons in the CST to ensure that the HPCS system could supply makeup water to the reactor pressure vessel. FSAR, Section 6.3.2.2.1, "[System

Design] High Pressure Core Spray (HPCS) System," also stated that the CSTs contain a reserve of approximately 135,000 gallons of water just for use by HPCS and reactor core isolation cooling (RCIC). Similarly, FSAR, Section 5.4.6.2.2.1.f., "[Reactor Core Isolation Cooling System Design] Description," stated that the total reserve storage for reactor pressure vessel makeup was 135,000 gallons."

In 1983, Calculation 5.52.070, "Setpoints - CST System," Revision 0, established the minimum required CST levels of 13.25 feet and 7.6 feet to meet the Technical Specification Bases. This calculation determined the level needed to ensure 135,000 gallons of water above the level at which the suction supply for the HPCS and RCIC systems is automatically transferred from the CSTs to the suppression pool. The automatic transfer of the HPCS system supply from the CSTs to the suppression pool was designed to be initiated by Level Switch HPCS-LS-1A or HPCS-LS-1B, both located on the HPCS standpipe in the reactor building.

In 1991, engineering personnel developed an improved estimate of when the automatic transfer would occur. Calculation E/I-02-91-1011, "Setting Range Determination for Instrument Loops HPCS-LS-1A & HPCS-LS-1B," Revision 0, was performed in 1991 and revised by Calculation Modification Record 96-0007 dated January 15, 1996. The team reviewed the calculation and the associated calculation modification record and found the licensee had considered the pressure drop in the piping from the CSTs, as well as other factors, to more accurately establish the relationship between the water level in the instrument standpipe and the actual level in the CST. In this calculation, the licensee determined that, under some flow conditions, the level sensed by the instruments located at the instrument standpipe could differ from the CST level. As shown in Calculation Modification Record 96-0007, the suction transfer could occur sooner than previously estimated. As a result, the team noted that the HPCS pump suction could automatically transfer from the CSTs to the suppression pool prior to the full 135,000 gallons being supplied to the reactor pressure vessel under some flow conditions.

The team asked if the minimum required CST levels in Technical Specification Surveillance Requirement 3.5.2.2 assured that the HPCS system could supply 135,000 gallons of makeup water to the reactor pressure vessel. In response to this question, the licensee issued Problem Evaluation Request 298-0899, "Results of Calculation E/I-02-91-1011 (HPCS-LS-1A & 1B) Not Incorporated into Calculation 5.52.070 (CST Setpoints)," dated July 17, 1998.

This problem evaluation report documented that the HPCS and RCIC systems remained operable. The 135,000 gallon volume requirement was not critical with respect to any safety function of the HPCS or RCIC systems. In addition, the licensee stated that the CST operating procedure maintains the CST level above 21 feet. The licensee stated that they have implemented additional administrative controls to ensure that an adequate CST level will be maintained and that they will either modify the plant or revise the technical specification and/or the Technical Specification Bases, as appropriate, to resolve this conflict.

This failure appeared to be related to the age and lack of references in the original plant design calculation, Calculation 5.52.070, that established the technical specification

values. The licensee stated that the more recent calculation revisions included an index of those interfacing documents that were impacted by the revision, as well as an index of references. The licensee had implemented a relational database to assist individuals revising engineering documents including calculations. This database contained related interface inputs and outputs for calculations and, when calculations are revised, the engineers updated the database. The licensee stated that older calculations have not been back fit with this design control unless they have been recently revised. The team concluded that the lack of a well documented original design basis contributed to a design control failure.

Based on the additional similar minor failures identified in this report (Sections 1.2 and 1.3.1) and in NRC Inspection Report 50-397/96-24, the team determined that the data base being used by the licensee to identify calculations impacted by revision of another calculation was not sufficiently reliable to be used as the only method for evaluating the impact calculation revisions would have on other older calculations.

10 CFR Part 50, Appendix B, Criterion III, "Design Control," states that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. The design basis CST capacity, as addressed in the FSAR and the Technical Specification Bases, were not correctly translated into the plant design. This is an example of a violation of 10 CFR Part 50, Appendix B, Criterion III (50-397/9815-01).

c. Conclusions

The team concluded that the HPCS pump would be provided with adequate available NPSH from both the CST source and the suppression pool source under accident conditions. With the exception of the available CST capacity issue, the team found that the HPCS system design was consistent with the applicable licensing, design, and operations documents. In the CST capacity case, the lack of a well documented original design basis contributed to a design control failure that was determined to be an example of a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control."

E1.1.2 HPCS Strainer Modification

a. Inspection Scope

The team reviewed one significant design modification to the mechanical portions of the HPCS system. Basic Design Change 96-0139-0A, "ECCS Suction Strainer Replacement," Revision 0, replaced the HPCS, low pressure core spray (LPCS), and residual heat removal (RHR) system strainers in the suppression pool in response to NRC Bulletin 96-03, "Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors."

b. Observations and Findings

The team found that the reason for change, functional objective, design description, impact on operation, and testing requirements for the modification were clearly stated in the modification package. The installation instructions were detailed and consistent with the safety evaluation. The screening for licensing basis and the 10 CFR 50.59 safety evaluation were complete and correct, the appropriate calculations were referenced, the post-modification testing requirements were appropriate, and the required plant documentation had been updated to reflect the modification. In general, the team found this modification package to be of high quality.

c. Conclusions

This recent design modification package was correctly prepared in accordance with the current procedures. The format was clear and easy to understand.

E1.2 HPCS Control System Design

a. Inspection Scope

The team reviewed various HPCS instrumentation and control design drawings, calculations, and isometric sketches to confirm compliance with applicable portions of the technical specifications and commitments made in FSAR, Chapters 6, 7, and 15; the licensee's controlled specifications; and correspondence to the NRC. The team also conducted walk downs of the main control room to evaluate the human factors aspects of the HPCS control panel layout. The team evaluated setpoint calculations for instruments that initiate and control the HPCS system and the translation of design requirements into the technical specifications. The team reviewed eight setpoint calculations.

b. Observations and Findings

HPCS Control System Logic

The team's review of HPCS and support system electrical control drawings, one-line power distribution drawings, piping and instrument drawings, and operating procedures resulted in the conclusion that the HPCS control scheme was designed to provide for automatic vessel level control between Level 2 (low) and Level 8 (high) or to provide for manual override as needed to respond to an anticipated transient without scram.

HPCS Main Control Room Panel Layout

The team noted that the majority of the HPCS controls and instrumentation were installed in conformance with good human factors practices on Panel H13-P601. The controls were laid out in a logical manner, and the operators would be able to observe the results of switch manipulations on nearby process indicators. With the exception of the keylock override Switches HPCS-RMS-S25 and -S26 for Injection Valve HPCS-V-4,

all necessary controls were laid out so that one operator could easily control the HPCS system with minimal movement.

Switches HPCS-RMS-S25 and -S26 were located on a panel several feet away from the other HPCS controls. These keylock override switches were installed under Plant Modification Request 92-0150-2 to expedite post anticipated transient without scram and loss of vessel level indication emergency procedures and were an improvement over past procedures that required the installation of jumpers rather than simple switch manipulations. Placing the switches in override on Panel H13-P625 will result in an annunciator window illuminating on the main HPCS control panel, Panel H13-P601. The team determined this to be an acceptable design feature.

During a review of the HPCS layout in the control room, the team noted the overall control room was well designed and maintained. Noise level and lighting observed under normal plant conditions were acceptable. The team noted obsolete recorders were replaced several years ago with more current technology recorders. The licensee consistently used the same make of recorder. The team determined this effort to present information to operators on similar devices was a strength.

Regulatory Guide Compliance

The team reviewed the HPCS indicators against Three Mile Island accident lessons learned described in Regulatory Guide 1.47, "Bypassed/Inoperable Status Indication," Revision 0, and Regulatory Guide 1.97, "Instrumentation for Light-Water Cooled Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 2. The team noted the HPCS out-of-service alarm panel had adequate system level and specific component alarm windows to meet Regulatory Guide 1.47 guidance.

The team noted that Operating License Condition 16 required the licensee to implement requirements of Regulatory Guide 1.97, with the exception of flux monitoring, prior to startup following the first refueling outage. Section C, "Regulatory Position," Paragraph 1.4 , stated that the instruments designated as Types A, B, and C and Categories 1 and 2 should be specifically identified on the control panels so that the operator can easily discern that they are intended for use under accident conditions.

During the panel walk down, the team noted that the following Regulatory Guide 1.97 Type A, B, and C, Category 1 and 2, post-accident monitoring instruments were not specifically identified on the control panels so that the operators could tell that they were intended for use under accident conditions:

- ECCS Pump Room Flood Elevation FDR-LI-1, 2, 3, 4, 5, and 6 (Type A, Category 1)
- Primary Containment Isolation Valves (Type B, Category 1)
- Neutron Flux Recorders WRM-LR-1,2, SRM-LR-602A,B, and IRM-LR-603A,B (Type B, Category 1)

- Building Gaseous Release Monitors PRM-RR-3 (Type C, Category 2)
- Standby Service Water Radiation SW-RIS-605 (Type C, Category 2)

A design engineer involved with the original post-accident monitoring commitments in FSAR, Section 7.5.1.1, and Operating License Condition 16 stated that the markings were described in Standard Engineering Detail, Human Factors Engineering Standard (HFES) -10, "Demarcation Standard," Revision 0. HFES-10, Section 3.1, required the use of 0.25-inch wide red demarcation lines to identify and enhance the visibility of Category 1 post-accident monitoring instruments; all other demarcation lines were to be black. The team noted that HFES-10 did not include a requirement for marking Category 2 post-accident monitoring instruments.

The licensee initiated Problem Evaluation Report 298-0898 to address this discrepancy. Based on a review of photo logs of the control room, the licensee determined that they were in compliance with the license condition for both Category 1 and 2 post-accident monitoring instruments, as required, prior to startup following the first refueling outage. The licensee stated that identification of the neutron flux recorder as a post-accident monitor, Category 1, parameter was probably lost when the recorders were replaced, but the indications were still qualified Class 1E devices. The licensee stated that the primary containment isolation valve status panel was removed either during construction or early after licensing because of design deficiencies and was replaced with position lights above each of the associated switches in various locations around the control room. While these indicators were not marked as post-accident monitors, the indications were still qualified Class 1E. They speculated that the remaining markings were likely removed and not reinstalled, when the control room was painted.

10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, "Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions." The failure to accomplish control panel marking for Category 1 instruments in accordance with HFES-10 and the failure to properly prescribe marking requirements for Category 2 post-accident monitoring instruments in instructions, procedures, and drawings is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (50-397/9815-02).

Interviews with licensed control room operators, several design engineers, and system engineers resulted in the observation that, in general, personnel were not aware of the Regulatory Guide 1.97 license condition and related commitment to identify post-accident monitor Category 1 and 2 devices. However, the licensee noted that operators received extensive training on the more general topic of which instruments could be relied upon post accident.

Setpoint Program

At original licensing, the licensee committed to determine instrument errors based on test and experience. During the early 1990s, the licensee stated they had subsequently conducted a large setpoint uncertainty calculation program. This program was

described in Procedure EES-4 "Setpoint Methodology" and was based on ISA-67.04, "Methodology for the Determination of Setpoints for Nuclear Safety Related Instrumentation." The results of this program were used as a basis for the improved technical specification submittal.

The licensee submitted their improved technical specifications in 1995. Technical Specification Bases, Sections B 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and B 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," in the improved technical specifications both state that the technical specification allowable values were derived from the analytic limits, corrected for process and all instrument uncertainties, except drift and calibration. The trip setpoints included in the licensee controlled specification manual are derived from the analytic limits, corrected for process and all instrument uncertainties, including drift and calibration.

Elevation Uncertainty

The team questioned the licensee regarding the need for inclusion of an uncertainty term in the reactor vessel level setpoint calculations to provide an allowance for construction elevation uncertainty. The licensee reviewed vendor supplied documentation related to reactor vessel fabrication and found that the dimensions for the as-built configuration of the vessel level taps had been measured (post-fabrication) to within ± 1/32 of the designed vessel level tap locations. The licensee also reviewed vendor documentation related to the development of analytical limits and found that the analytical limits included the measured as-built elevation uncertainties. Therefore, it was not necessary to include an additional allowance for construction elevation uncertainty in the reactor vessel level setpoint calculations.

Environmental Effects

The team found that Calculation E/I-02-91-1051, "Setting Range Determination for MS-LIS-31A, -31B, -31C, -31D, -37A, -37B, -37C, and -37D," Revision 0, contained the assumption that, although the instruments were located inside a harsh environment, the uncertainties associated with the harsh environment were not required to be included in the analysis. The team questioned the validity of this assumption because reactor vessel Level 2 signals generated by Level Indicating Switches MS-LIS-31A, -B, -C & -D were used for long-term HPCS level control.

The licensee initiated Problem Evaluation Report 298-0900 to address this issue and determined that MS-LIS-31A, -31B, -31C, and -31D remained operable. The licensee found that there was enough existing margin between the technical specification allowable value for HPCS actuation at Level 2 and the analytical limit for Level 2 to accommodate the larger harsh environment uncertainties. Because the technical specification allowable value remained correct and the more limiting setpoints in the plant calibration procedure continued to ensure that the allowable value of the technical specifications would not be exceeded, the team concluded that the calculation error had not adversely impacted the HPCS control system design.

The team requested that the licensee verify that this problem did not affect the other reactor vessel instruments. The licensee identified that Switch 1 on Switches MS-LIS-37A, -37B, -37C, and -37D could potentially be affected by the same error. This switch was used for initiation of the automatic depressurization system (ADS), LPCS, and low pressure coolant injection (LPCI) at reactor vessel water Level 1 (consistent with Technical Specification Table 3.3.5.1-1, "Emergency Core Cooling System Instrumentation," Items 1.a, 2.a, 4.a, and 5.a).

For the purposes of promptly evaluating operability, the licensee assumed that all of these switches were required to operate post-accident. The licensee noted that for the Level 1 switches, the additional uncertainty introduced because of harsh environmental effects could not be accommodated between the existing technical specification allowable value and the analytic limit. The licensee determined that a revision to the technical specification allowable value for Level 1 from -148-inches reactor vessel water level to -142.3-inches reactor vessel water level would be required, if these switches were required to operate post-accident. The most recent calibration settings were sufficiently conservative to assure the Level 1 trip would occur at a reactor water vessel level above -142.3-inches reactor vessel water level; therefore, the level switches were operable. The team determined that the licensee did an effective extent of condition review. The licensee planned additional research to determine if all the Level 1 switches were required to operate post-accident.

Subsequent to the conclusion of the onsite inspection, the team requested a copy of the environmental qualification report for Switches MS-LIS-37A, -37B, -37C, and -37D, used for initiation of ADS, LPCS, and LPCI at reactor vessel water Level 1. The licensee provided documentation that stated these switches were required to be able to change state for 4,320 hours, while subjected to harsh environment conditions. On this basis, the team concluded the switches were required to operate post-accident and that the current technical specification allowable values were incorrect in that a more conservative value was needed to adequately include post-accident harsh environment uncertainties and assure that the associated analytical limit was met.

10 CFR Part 50, Appendix B, Criterion III, "Design Control," states, in part, "Measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application . . . are correctly translated into specifications, drawings, procedures, and instructions." The failure to correctly translate the Technical Specification Bases commitment to derive the allowable values from the analytic limit corrected for process and all instrument uncertainties except drift and calibration into the technical specification for Reactor Vessel Water Low Low Low - Level 1 is a an example of a violation of 10 CFR Part 50, Appendix B, Criterion III (50-397/9815-01).

c. Conclusions

The installed instrumentation and controls met HPCS system logic requirements. The majority of the HPCS controls and instrumentation were installed in conformance with good human factors practices, and the licensee routinely trained the operators regarding the availability and use of particular instruments during accidents. However, the licensee did not meet Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear

Power Plants To Assess Plant Environs Conditions During and Following an Accident," guidance to specifically identify to operators instruments intended for use under accident conditions. Control panel marking was not always accomplished in accordance with Human Factors Engineering Standard (HFES) -10, "Demarcation Standard," Revision 0, Section 3.1, which required the use of 0.25-inch wide red demarcation lines to identify and enhance the visibility of Category 1 post-accident monitoring instruments. In addition, marking requirements were not prescribed in documented instructions for Category 2 post-accident monitoring instruments. The failure to follow procedures and the failure to prescribe adequate procedures were determined to be examples of a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

In general, HPCS setpoint analyses were acceptably developed based on ISA-67.04, "Methodology for the Determination of Setpoints for Nuclear Safety Related Instrumentation." However, the team identified a failure to include harsh environment effects on the reactor vessel Level 2 switch. In this case, there was adequate margin between the analytical limit and the existing technical specification allowable values to accommodate the error. The licensee identified a similar issue with the reactor vessel Level 1 switches that will likely require a technical specification revision. The failure to adequately include post-accident harsh environment uncertainties in the technical specification allowable value for reactor vessel water Level 1 was an example of a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control."

E1.3 HPCS Electrical System Design

E1.3.1 HPCS Electrical Design Capability

a. Inspection Scope

The team reviewed calculations to evaluate the basis for the derated ampacity assigned to both alternating current (ac) and direct current (dc) HPCS power cables and the selection and coordination of various protective devices. The team reviewed calculations to evaluate the capability of HPCS system components to withstand the maximum available short-circuit currents in the ac and dc distribution systems. The team reviewed procedures and calculations to confirm that the Division 3 Diesel Generator trips were functional, especially those not bypassed, and to check that the generator would not exceed its nameplate power ratings during the initiation and operation of the HPCS system. The team reviewed calculations to confirm adequate minimum expected ac and dc voltages. The team also reviewed the cable routing and heat trace design for the HPCS system.

b. Observations and Findings

Ampacity of AC and DC Power Cables

The team found that all power cables were conservatively derated, assuming worst case loading in trays and conduits, for environmental conditions that can cause higher operating cable temperatures. Calculation 02.06.20 determined a cable's ampacity by

the calculated-cable-depth method used in National Electric Manufacturers Association Publication WC51-1975, "Ampacities Cables in Open-top Cable Trays" This method assumed uniform heat production per cable tray area and then determined a given cable's ampacity based on the calculated depth of all cables in the tray. The licensee conservatively applied the above formula and then applied derating factors for temperature in a specific area; covers on trays; fire barriers; trays covered with Thermo-Lag; etc. For conduits, the free air ampacity was derated for the number of cables in a conduit and the number of conduits in proximity to one another in an array during routing with the largest array in a given route being most limiting. The derating factors used were the latest conservative values proposed by industry. After taking this approach, the allowable ampacities of some cables were less than their required full load currents. The above formula for calculated cable depth in tray was then adjusted to take into account the intermittently loaded cables and spare cables in a given tray. This meant heat production in a given tray dropped, but the allowable heat tolerance of a given cable would rise permitting higher ampacities for the problem cables.

4 kV Over Current Protection

The team found that the over current protection for the 4 kV supply to the HPCS system equipment was properly coordinated. When the respective time overcorrect curves for the normal feed to 4 kV Switchgear SM-4 , the HPCS pump, and the 4 kV feeder to Motor Control Center MC-4A, respectively, were plotted on the same log-log paper, it was evident that coordination was achieved for all fault current values including the starting current of the HPCS pump and the inrush current of the transformer supplying Motor Control Center MC-4A.

480 Volt Over Current Protection

The team initially noted that the over current relay on the feeder from 4 kV Bus SM-4 to 480 volt Motor Control Center MC-4A did not appear to coordinate with the 100 ampere breaker on Motor Control Center MC-4A that supplied the Division 3 Diesel Generator auxiliary ac panel. In 1985, the licensee issued Field Change Request 85-9528-0-01 to revise the setting of the over current relay, but at the time of the inspection had not implemented these changes in the field. The team was initially concerned that a 1985 field change had not been implemented. However, the team performed a further evaluation and independently calculated the actual currents for the ac loads. Even though there was some slight overlapping of the time-current curves for the respective protective devices involved, the overlap occurred at fault current values that were not expected to occur. The team noted that only three phase fault currents were relevant, because the 480-volt system was high resistance grounded. The team determined that the licensee had acceptably prioritized implementation of this field change based on available fault currents.

AC & DC System Fault Analysis

The team found that electrical buses and components associated with the HPCS system had been properly sized to withstand the calculated fault currents. Calculations E/I-02-92-13, "Short Circuit Current Calculation for 480 V Systems, " Revision 0, dated

December 22, 1994, and Calculations E/I-02-92-09, "Short Circuit Current Calculation for 4.16 and 6.9 kV Buses," Revision 0, dated June 8, 1992, demonstrated that the electrical buses and components were capable of withstanding the maximum available short-circuit current. The team reviewed Calculation E/I-02-91-06, "Short Circuit Calculation for the 250 V, 125 V, and 24 V dc Systems," Revision 0, dated March 26, 1993, and determined that all HPCS dc distribution system components had sufficient short-circuit withstand capability to endure the low magnitude fault that was calculated to be available in the dc system.

However, the team noted that all three calculations included incorrect design assumptions for conductor temperature. The licensee assumed a conductor temperature of 50º Centigrade to calculate the cable resistances in the dc system and 75º Centigrade to calculate the cable resistances in the ac system. These assumptions were not conservative, because actual room temperatures can go as low as 40º Centigrade. A lower temperature decreases resistance, resulting in increased fault current. As discussed in the previous subsection, in some cases breaker coordination and circuit protection were acceptable based in part on the expected fault currents. These cases will need to be reverified after the fault currents are recalculated.

The licensee agreed and included this concern in Problem Evaluation Report 298-0963.

10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, "Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions." Step 3.1.14 of Engineering Instruction EI 2.15, "Preparation, Verification and Approval of Calculations," effective July 1 through August 9, 1991, and Step 4.1.15 of Engineering Department Procedure EDP 2.15, "Preparation, Verification and Approval of Calculations," Revision 0, effective August 10, 1991, through March 1996 required that calculations be verified by ensuring that all aspects are technically correct, complete, and accurate. The failure to adequately verify the conductor temperature input assumptions for Calculations E/I-02-91-06, E/I-02-92-13, and E/I-02-92-09 resulted in an indeterminate conclusion regarding the adequacy of the selected electrical protective equipment. This failure is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (50-397/9815-02).

Coordination of Protective Devices in the DC System

The team determined that there was lack of coordination between the Division 3, battery 125-ampere output breaker, and the 20- and 70-ampere molded-case breakers located at Distribution Panel E-DP-S1/HPCS. The calculated fault current at the load-side terminals of any breaker in Distribution Panel E-DP-S1/HPCS was 2020 amperes, which would cause the battery output breaker and the respective molded-case breaker to open simultaneously.

The team found that the licensee had previously identified the lack of coordination between the Division 3 battery main breaker and the feeder breakers in Distribution Panel E-DP-S1/HPCS in September 1992 and had documented the design deficiency on Problem Evaluation Report 292-0409. The responsibility for rectifying this design

deficiency has been transferred among a variety of documents, but the latest one was Technical Evaluation Request 97-0130-0 initiated in June 1998, which had not been resolved. The team found that the licensee had not promptly corrected this design deficiency, in part, based on the fact that the HPCS system was not designed to be single failure proof. The licensee had reasoned that for many loads on the distribution panel, the loss of the load itself would cause loss of the HPCS system and; therefore, the breaker coordination issue was moot.

However, the team identified that the lack of coordination was a design deficiency that should be addressed, because proper application of the single failure criterion required that failures resulting from design deficiencies be pre-assumed. Some loads on the distribution panel were not required to operate the HPCS system, but a fault at the load-side terminals of the supply breakers for these loads would still prevent operation of the HPCS system. For example, the Division 3 Diesel Generator lube oil Pump DLO-P-10 was supplied from Distribution Panel E-DP-S1/HPCS and was not essential to operation of the HPCS system. The lube oil pump was only required for long-range maintenance and reliability of the Division 3 Diesel Generator. With the current design, a fault at the load-side terminals of the supply breaker for lube oil pump DLO-P-10 could cause the battery output breaker to trip, which would unnecessarily prevent the operation of the HPCS system.

The team reviewed the licensee's commitments to provide proper breaker coordination. The team found that in FSAR, Section 8.3.2.1.2.2, the licensee had committed to design the 125-volt dc system in accordance with applicable clauses of IEEE Standard 308-1974. IEEE Standard 308-1974, Section 5.3.1 (6), "[Direct-Current Systems, General] Protective Devices states that, "Protective devices shall be provided to limit the degradation of the Class 1E power systems." The team determined that the current protective device design for 125-V dc Distribution Panel E-DP-S1/HPCS did not adequately limit degradation of the HPCS Class 1E Power system when a fault occurred at the load side breakers that supply non-critical loads.

10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states that measures shall be established to assure that conditions adverse to quality such as deficiencies are promptly corrected. The failure to promptly correct the dc breaker coordination deficiency is a violation of 10 CFR Part 50, Appendix B, Criterion XVI (50-397/9815-03).

The licensee agreed and issued Problem Evaluation Report 298-0961. This problem evaluation report included plans to correct the design deficiency during Refueling Outage R-14 and to evaluate methods of prioritizing and resolving documented design deficiencies to ensure timely resolution of open issues.

The team determined that this inspection report adequately describes the reasons for the violation, and the actions taken to correct and prevent recurrence of the violation. Therefore, the licensee is not required to respond to this violation.

Protection of Penetration Feedthroughs

The team found that the HPCS system penetration feedthroughs were adequately protected from damage caused by over current. There are only two circuits that penetrate containment for the HPCS system, and they are for position indication for testable check Valve V-5 and for manually operated Valve V-51. Both valve indication circuits have two over current devices to protect their feedthroughs from high fault currents. The indication circuit for Valve V-5 was disconnected, but the calculation showed that both valve indication circuits had their penetration feedthroughs adequately protected by two protective devices in series. If one device fails to open, then the other one will respond to open the circuit path to the feedthroughs.

HPCS Diesel Generator Capability

The team reviewed Calculation E/I-02-91-03, "Div.1, Div.2, and Div.3 Diesel Generator Loading Calculation," Revision 6, and determined that peak accident loading of the Division 3 Diesel Generator at 2610.2 kilowatts was just slightly above its continuous rating of 2600 kilowatts and was well within its 2000 hour rating of 2850 kilowatts. The only major load on the Division 3 Diesel Generator was the HPCS pump. Based on a review of the simulated loss of coolant accident tests for HPCS initiation, the team determined that the Division 3 Diesel Generator could safely start all required HPCS loads.

The team found that the Division 3 Diesel Generator trips were functional and that appropriate trips were bypassed to maximize HPCS availability to perform it's safety function. The team reviewed documentation of the most recent performance of Procedure MMP-DG3-B103, "Diesel Generator DG-3 Mechanical Inspection," Revision 1, and found that the over speed trip at 1037 RPM was adequately tested. Using Procedure TSP-DG3/LOCA-B501, " HPCS Diesel Generator DG3 LOCA Test," Revision 0, the licensee verified that the appropriate trips would be bypassed during a loss of coolant accident. The licensee also had performed periodic maintenance to confirm the readiness of the only Division 3 Diesel Generator trip that was not bypassed, the differential current relay.

During implementation of Procedure TSP-DG3/LOCA-B501, the licensee also verified that the fuel oil storage tank level was at 44622 gallons (the technical specification limit was 33,000 gallons) and that the emergency core cooling system activation signal initiated the HPCS system.

4 kV Available Voltage During a LOCA and Starting of Large Motors

The team found that during a LOCA, Division 3 was supplied by Transformer TRS from the 230 kV system. The off-load tap setting for Transformer TRS was .975. This tap setting effectively raised the source voltage to 1.025 per unit. The worst case voltage drops will be experienced when the HPCS system was supplied from the offsite source and not the Division 3 Diesel Generator.

Calculation E/I-02-87-07, "WNP-2 Plant Main Bus Voltage Calculation," Revision 3, showed that for the degraded grid voltage relay allowable minimum setting of 3684.45 volts ac, the available voltage at Motor Control Center MC-4A would be about 415 volts ac. Calculation E/I-02-90-01, "Low Voltage Systems Loading and Voltage Calculations," Revision 4, indicated that with 415 volts at Motor Control Center MC-4A all of the Motor Control Center MC-4A loads would be supplied a minimum of 408 volts ac at their terminals. This was less than the preferred value of 90 percent of nominal voltage or 414 volts ac and would cause the loads (especially the motor loads) to operate at increased temperatures because of the reduced voltage. The majority of the loads were motor operated valves that operate only intermittently during a HPCS initiation and would not be significantly affected by this concern. Continuous HPCS loads would experience an indefinable loss of thermal life because of the expected increase in current during low voltage conditions. However, since HPCS only operates infrequently, the team determined that this minor design discrepancy would have negligible impact on the overall reliability of the HPCS system.

All HPCS ac loads had sufficient voltage to operate even when starting motors on the 4 kV buses. For worst case starting voltages at Bus SM-4, the team determined that the HPCS system could be initiated without causing the degraded grid voltage relay to dropout.

Minimum AC Voltages at Low Voltage Buses

The team found that the licensee satisfactorily demonstrated that all ac loads supplied from Motor Control Center MC-4A had sufficient voltage to operate properly for all operating conditions. The mechanical calculations for the HPCS motor operated valves assumed the terminal voltage at each valve's motor to be 80 percent of 460-volts ac, unless a higher voltage was required for a motor operated valve to develop its required torque and thrust. Some motor operated valves required more than 80 percent voltage to open or close. For example, Valves V-23 and V-12 required 85 percent and 88 percent voltage, respectively, to develop their required torque. In Calculation E/I-02-90-01, the licensee determined that the available voltage at each motor operated valve's motor terminals was higher than that needed to assure proper operations of the valve during the starting of motors at Motor Control Center MC-4A and upstream buses.

Minimum DC Voltages at Low Voltage Buses

The team's review confirmed that sufficient voltage was available at the terminals of most dc power loads except for lube oil pump DLO-P-10. When the starter for the Division 3 Diesel Generator lube oil pump DLO-P-10 was relocated from dc Distribution Panel E-DP-S1/HPCS to near the pump itself, the voltage drop calculation was not revised to incorporate this circuit change. While this was a another indicator of the failure to update calculations as changes occur, the team noted that lube oil pump was not required to support the HPCS system safety function. The licensee agreed that the voltage drop calculation had not been appropriately revised and documented it on Problem Evaluation Report 298-0985. This failure to update the voltage drop calculation constitutes a violation of minor significance and is not subject to formal enforcement action.

The team also noted that Calculation 2.07.04, "D.C. Cable Voltage Drop," Revision 5, did not analyze voltage drops for instrumentation, relays, etc., in downstream panels from the dc Distribution Panel E-DP-S1/HPCS. The licensee planned to determine how they assured that loads of this type had the requisite pickup voltage at their terminals under minimum voltage conditions.

Cable Routing

The licensee, at the team's request, provided a copy of Cable and Raceway Report CARPS 2.1 for power and control cables to HPCS motor operated valves and the HPCS pump. This document showed that these cables were routed exclusively with Division 3 cables and in Division 3 raceways, which supported the separation policy.

Heat Tracing

The team asked the licensee about the heat tracing of the HPCS standby service water piping. Only the return line was heat traced at the point where it rose out of the ground and then drops down to facilitate discharging HPCS standby service water into standby service water Pond A. The licensee stated that this heat tracing was supplied by a Class 1E power supply, was alarmed for power failure, had indication that power was available, and that the heat tracing alarms and indications were routinely monitored by a roving operator.

c. Conclusions

In general, the electrical equipment for the HPCS system was well designed. Both ac and dc power cables for the HPCS system were appropriately sized. With some exceptions, the electric protective devices were appropriately selected and coordinated. The team concluded that the licensee had not appropriately assessed the significance of some breaker coordination errors in the dc system and did not promptly correct these design deficiencies. This was an example of a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action." While some selections were marginal, the team found that, in general, breakers were properly selected to withstand the maximum calculated available short-circuit currents in the ac and dc distribution systems. However, in conflict with the licensee's procedures, the calculations to determine available short-circuit currents contained nonconservative temperature assumptions. This was an example of a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Breaker coordination and protective device selection will need to be reassessed after the licensee correctly calculates the available short-circuit currents. The team found that the Division 3 Diesel Generator had acequate capacity. The protective trips were functional and appropriate trips were bypassed on a safety actuation signal. The team determined that the minimum expected ac and dc voltages were adequate to meet HPCS system operating requirements. The team also determined that the cable routing and heat trace design for the HPCS system were satisfactory.

E1.3.2 Electrical Design Changes

a. Inspection Scope

The team reviewed Plant Modification Record 93-0049-0, "HPCS-V-10 & 11 Time Delay," and 93-0052-0, "HPCS-MO-4 Close on Torque," to determine whether the intent of the original design basis was maintained and to confirm that safety functions were not compromised by the design change.

b. Observations and Findings

Test Return Valve Auxiliary Relay Replacement

Plant Modification Record 93-0049-0, replaced an instantaneous pickup auxiliary relay in the opening control circuits of HPCS test return Valves V-10 and V-11 with an instantaneous pickup and delayed drop-out relay. This relay was modified to delay the close signal until the valve's opening motion had ceased, thus preventing high actuator currents and protective device actuations, which are caused by sudden motor reversals. The plant modification record appeared to the team to resolve the longstanding design concern. This design change did not impact the original safety purpose of each valve, which was containment isolation during an accident, since it only delayed valve closing if the valve was still trying to open. The plant modification record properly addressed the seismic mounting of relays, ensured that the relays had sufficient rating for the available current and voltage in each valve's control circuit, and all other relevant design concerns.

Use of Torque Switch to Control Closure for HPCS Injection Valve V-4

Plant Modification Record 93-0052-0, changed the closing control circuit of HPCS Injection Valve V-4 to prevent damage to the valve by allowing a torque switch to control closure in lieu of a limit switch. The primary design safety function of this valve was to open to inject water into the vessel during an accident, which was not altered by this design change. The close safety function was to prevent vessel overfill and containment isolation. The post-modification test for this modification verified the new settings of the torque switches along with verifying that back leakage was not altered from what it was prior to this modification.

c. Conclusions

The plant modification records addressed all relevant design and safety issues and effectively verified the design changes by post-modification testing.

E2 Engineering Support of Facilities and Equipment (93809)

E2.1 HPCS System Walk Down

a. Inspection Scope

The team performed a walk down of the accessible portions of the HPCS and HPCS standby service water systems to verify that the system configuration was consistent with the design basis. The walk down included the CST area, supply piping from the CST to the HPCS pump, the HPCS pump room, various reactor building areas that contained HPCS piping and valves, the HPCS standby service water pump area, and the Division 3 Diesel Generator room.

b. Observations and Findings

The team found the system configuration to be consistent with the HPCS, condensate supply, and standby service water system flow diagrams in the areas observed. In addition, the team observed that housekeeping was very good. The team did not observe any improperly stored material or unsecured temporary equipment in these areas.

c. Conclusions

Based on the area walk downs, the HPCS and HPCS standby service water system configurations were consistent with the design basis. The plant reflects the licensee's attention to housekeeping. The team did not observe any improperly stored material or unsecured temporary equipment.

E2.2 HPCS Valve Operation

a. Inspection Scope

The team reviewed the available licensing, design, and operations documents related to the capability of HPCS system valves to perform their required functions under accident conditions.

b. Observations and Findings

Calculation C106-92-03.02, "WNP-2 HPCS System MOV Design Basis Review," Revision 2, documented the system level design basis review of the motor operated valves in the HPCS system that were included in the motor operated valve program developed to meet Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." This calculation documented the maximum expected differential pressure, maximum line pressure, maximum flow rate, maximum fluid temperature, and stroke time for each valve. The team reviewed this calculation and found it to be complete and correct.

c. Conclusions

The team found that the HPCS system valve design was consistent with the applicable licensing, design, and operations documents and that the valves were capable of performing their functions under accident conditions.

E2.3 HPCS Mechanical System Surveillance Testing Acceptance Criteria

a. Inspection Scope

The team reviewed the available licensing, design, and operations documents related to surveillance testing of HPCS system mechanical components. This review included the applicable technical specifications and surveillance procedures.

b. Observations and Findings

HPCS Pump Testing

Technical Specification Surveillance Requirement 3.5.1.4 required the HPCS pump flow to be greater than or equal to 6350 gpm and the pump head to be greater than or equal to 200 psid. These variables were verified by the inservice testing program. Surveillance Procedure OSP-HPCS/IST-Q701, "HPCS System Operability Test," Revision 3, included the inservice testing of the HPCS pump. The low action limit for pump flow was 6500 gpm, and the low action limit for pump discharge pressure was 380 psig. Procedure PPM 7.4.5.1.11, "Record of Reference Values and Acceptance Criteria Changes for ASME Pumps and Valves," dated April 20, 1992, provided the correction between an indicated flow of 6500 gpm and an actual flow of 6350 gpm under test conditions. Calculation ME-02-90-017, "Pressure Drop Verification for the HPCS System," Revision 0, determined that a pump discharge pressure of 380 psig would correspond to a pump head of 200 psid. The team reviewed these documents and found them to be correct and complete.

HPCS Valve Testing

The Inservice Testing (IST) Program Plan, Second 10-Year Interval, Revision 1, identified the required testing for the HPCS system valves. Surveillance Procedures OSP-HPCS/IST-Q701and OSP-HPCS/IST-R701, "HPCS Check Valve Operability - Refueling Shutdown," Revision 1, included the inservice testing of HPCS system valves. The team reviewed these documents and found that the procedures correctly implemented the program plan requirements.

Section 2 of the Program Plan stated that it complied with the requirements of 10 CFR 50.55a(b)(2) and 50.55a(f). The 1989 edition of ASME Section XI was incorporated into Paragraph 50.55a(b) by rulemaking on September 8, 1992. The 1989 edition specified that the rules for the inservice testing of valves were stated in the ASME/ANSI Operations and Maintenance (OM) Standards, Part 10, "Inservice Testing of

Valves in Light-Water Power Plants." The applicable revision was the OMa-1988 Addenda to the OM-1987 Edition. OM-10 stipulated that Category A valves are those valves with functions in which the closed valve seat leakage was limited to a specific amount.

The team noted that the valves required to provide isolation between the HPCS system and the CSTs under accident conditions were not classified as Category A and were not required to be leak rate tested by the IST Program Plan. Motor Operated Valve V-1 (14-inch) and Check Valve V-2 (20-inch) were in the CST suction line. Motor Operated Valves V-10 and V-11 (10-inch) were in the HPCS test line to the CST. All these valves would be closed to isolate the HPCS system from the CST, if the HPCS system was taking suction from the suppression pool after an accident. It appeared that any leakage through these valves could be released to the environment through the vented CSTs.

The IST valve classification of Valves HPCS-V-1, 2, 10, and 11 did not appear consistent with FSAR, Section 6.2.3, "Secondary Containment Functional Design." Section 6.2.3.2, "System Design," stated, "The control rod drive, HPCS, RHR, LPCS, fuel pool cooling, and RCIC systems connect to systems that terminate outside containment. Each of the water leak paths has been evaluated and the isolation valves have been assigned leakage values based upon allowable ASME leak rates. The summation of the water leakage for all the water leak paths was equated to 0.03 standard cubic feet per hour (scfh) of air."

Engineering Technical Memorandum TM-2099, Revision 0, which formed the basis for part of FSAR, Section 6.2.3.2, established analytical leakage limits for liquid leakage paths that originated in primary containment and would bypass secondary containment on a "per valve basis," based upon allowable ASME leak rates. The team determined that, since these valves were not leak tested, the leakage limits assumed in Technical Memorandum TM-2099 were unrealistically low values for valves in service.

The team asked if the IST classification of these valve was consistent with the licensing basis. In response to this question, the licensee investigated the history of this issue and concluded that, while the IST classification was not consistent with the current licensing basis, it was the licensing basis that was in error. The licensee issued Problem Evaluation Report 298-0928, "FSAR Value for Secondary Containment Bypass Leakage Limit was Inappropriately Being Applied to Liquid Leakage Bypass Paths," dated July 28, 1998. The licensee planned to correct their licensing basis to make it clear that their current testing practices were adequate for these secondary containment bypass valves.

The team reviewed the licensee's basis for their position. The licensee determined that the initial plant licensing basis assigned a secondary containment bypass limit of 0.74 scfh to four gaseous leakage paths and did not include explicit consideration of liquid bypass leakage paths. After initial licensing, the licensee identified additional gaseous bypass leakage paths. The associated valves were included in FSAR Table 6.2-16, "Primary Containment Isolation Valves," and were added to the local leak rate test program. The overall 0.74 scfh limit was not changed to accommodate the additional gaseous leak paths.

In 1989, the licensee identified several liquid bypass leakage paths that had not been explicitly addressed during plant licensing. To ensure that the original 10 CFR Part 100 calculations remained valid, the licensee developed an equivalence between the gaseous and liquid bypass leakage paths, utilizing Standard Review Plan 15.6.5, Appendix B, and assuming that 10 percent of the liquid becomes airborne on a volumetric basis. They included the gaseous equivalent of the anticipated liquid bypass leakage in their estimate of total gaseous leakage. The licensee determined that the total predicted liquid leakage rate was equivalent to a gaseous leakage of .03 scfh. This value was subtracted from the 0.74 scfh limit to establish the remaining gaseous leakage limit of 0.71 scfh. This evaluation was documented in Interoffice Memorandum SS2-PE-89-0646, "Potential Bypass Leakage and Unmonitored Effluent Paths," dated June 22, 1989.

The application of a portion of the secondary containment bypass limit of 0.74 scfh to liquid bypass leakage paths was added to the licensing basis in 1996. FSAR/Technical Specification Bases Change Notice 95-072, Revision 0, was approved on May 8, 1996, revising FSAR, Section 6.2.3.2, to include a discussion of the liquid bypass leakage being equated to 0.03 scfh of gaseous leakage. Engineering Technical Memorandum TM-2099, "Secondary Containment Bypass Leakage," Revision 0, formed the basis for part of this FSAR change. TM-2099 stated that the approach used to correlate liquid leakage rates to equivalent gaseous leakage rates was similar to Standard Review Plan 15.6.5, Appendix B, with 10 percent of the leakage assumed to become airborne.

Based on questioning from the team, the licensee concluded that the calculation method used to determine the equivalence between airborne and liquid secondary containment bypass leakage in both Interoffice Memorandum SS2-PE-89-0646 and Engineering Technical Memorandum TM-2099 was technically inaccurate and did not implement Standard Review Plan 15.6.5.

During this inspection, the licensee performed an additional informal analysis of the impact of the liquid leakage bypass paths using a new method and determined that the offsite and control room doses would remain within the limits of 10 CFR Part 100 guidelines and the 10 CFR Part 50, Appendix A, General Design Criteria 19 limits. Based on this new method, the analyst determined that the low population zone thyroid dose consequences would be 2.21 rem/gpm of liquid leakage. Therefore, a total liquid bypass leakage rate of greater than approximately 100 gpm would be required to exceed the limits of 10 CFR Part 100 guidelines and the 10 CFR Part 50, Appendix A, General Design Criteria 19 limits. The licensee stated that the impact of any potential liquid bypass paths must be individually evaluated to determine the actual anticipated conditions at the point of release, the timing and holdup capacity, any additional dilution factors, applicability to the accident scenario being evaluated, and that Engineering Technical Memorandum TM-2099 and the FSAR would be updated to reflect these factors.

The licensee concluded that an assumption of a total system leakage limit rather than individual valve leakage limits was appropriate for these secondary containment liquid bypass paths. Therefore an IST classification of Category A was not applicable to the valves required to isolate liquid bypass leakage paths. The licensee stated that leak tightness of all liquid bypass paths would continue to be demonstrated by Type A Containment Leak Rate Testing. The liquid leakage necessary to exceed the analyzed

limit was of such a magnitude (approximately 100 gpm) that during the course of normal plant operation, these potential liquid leakage paths could be demonstrated to be adequately leak tight by virtue of relatively stable CST level, reactor water sump and tank levels, and standby service water system radiation levels. The team agreed that an IST classification of Category A was not applicable to the valves required to isolate the liquid bypass leakage paths, if leakage rates of approximately 100 gpm were found to be acceptable and the FSAR was appropriately revised.

The team reviewed the licensee's informal analysis and questioned the new calculation method used to determine the equivalence between airborne and liquid secondary containment bypass leakage. For the configurations being considered, the Standard Review Plan 15.6.5, Appendix B, Revision 1, stated that if the calculated flash fraction was less than 10 percent or if the water was less than 212° F, then 10 percent of the Iodine in the leakage should be assumed to become airborne unless a smaller amount was justified based on actual sump pH history and ventilation rates. The licensee's informal analysis did not assume that 10 percent of the Iodine in the liquid leakage becomes airborne. Instead the informal analysis was based on a General Electric study that determined that the release fraction would be less than 10^{-3} (0.1 percent) with 185º F suppression pool water. The team did not verify the applicability of the reduced release fraction based on the General Electric study to this application during the inspection. This release fraction had a significant effect on the analysis results. This item is unresolved pending completion of an NRC review of the application of the General Electric study to the release fraction determination (50-397/9815-04).

In 1996, the licensee submitted Letter GO2-96-199, "Request for Amendment to Secondary Containment and Standby Gas Treatment System Technical Specifications," dated October 15, 1996. This amendment had not been approved by the NRC at the time of the inspection. The proposed change would increase the allowable secondary containment bypass leakage from 0.74 scfh to 18 scfh. This change was based on analyses that have shown that the offsite and control room doses would remain within the limits of 10 CFR Part 100 guidelines and the 10 CFR Part 50, Appendix A, General Design Criteria 19 limits. The licensee stated that the analyses did not specifically address liquid leakage.

c. Conclusions

With the exception of valve leakage testing, testing of the HPCS system mechanical components was consistent with the applicable licensing, design, and operations documents. This testing was sufficient to verify the capability of the mechanical equipment to perform its required functions under accident conditions.

With regard to valve leakage testing, the licensee identified several liquid secondary containment bypass leakage paths in 1989 and was proactive in addressing the effect of these paths on the design basis by establishing a reduced total gaseous bypass leakage limit. However, the licensee did not effectively implement the design controls required to recognize the valve leakage testing requirements associated with assigning valve specific leakage limits. In addition, the calculation method used to determine the equivalence between airborne and liquid bypass leakage was not well documented and was in error.

Based on the results of an informal analysis performed by the licensee during this inspection and the licensee's statement that the FSAR will be revised to eliminate valve specific leakage limits for these liquid bypass leakage paths from the design basis, the licensee's position that an IST classification of Category A was not applicable to the valves required to isolate the liquid bypass leakage paths was found to be appropriate. However, the team did not verify the applicability of the calculation method for determining the Iodine release fraction used in this informal analysis during the inspection. This release fraction had a significant effect on the analysis results. This item is unresolved pending completion of NRC review of the applicability of this calculation method.

E2.4 HPCS Standby Service Water Thermal Performance Testing Acceptance Criteria

a. Inspection Scope

The team reviewed the capability of the HPCS standby service water system to provide an adequate cooling water supply to the Division 3 Diesel Generator Heat Exchanger DCW-HX-1C, the Division 3 Diesel Generator room Cooling Coils DMA-CC-31 and 32, and the HPCS pump room cooling Coils RRA-CC-4. The historical thermal performance monitoring data for the Division 3 Diesel Generator Heat Exchanger DCW-HX-1C was reviewed in detail.

b. Observations and Findings

A summary of the historical thermal performance monitoring data for the Division 3 Diesel Generator Heat Exchanger DCW-HX-1C from 1990 through 1998 indicated that the heat exchanger performance had been maintained at or above 40 percent of the design heat transfer coefficient value for this heat exchanger. This thermal performance monitoring data had been obtained and evaluated in accordance with Test Procedure 8.4.63, "Thermal Performance Monitoring of DCW-HX-1C," Revision 5.

Calculation ME-02-92-242, "DCW-HX-1C Performance Evaluation," Revision 0, specified that an overall heat transfer coefficient of at least 208 BTU/(hr ft^2 F), which was 40 percent of the design value of 520 BTU/(hr ft^2 F), was required to ensure acceptable thermal performance under accident conditions. The team's review of this calculation indicated that this 40 percent acceptance criterion was developed in Calculation ME-02-92-0243, "DCW-HX-1C Design Performance Requirements," Revision 0, and was based on a design HPCS standby service water flow of 910 gpm to Heat Exchanger DCW-HX-1C. The team noted that heat transfer was affected by fouling and flow.

Flow balance test Surveillance Procedure OSP-SW-M103, "HPCS Service Water Valve Position Verification," Revision 2, allowed an acceptable flow range of 780 gpm to 960 gpm to Heat Exchanger DCW-HX-1C. The purpose of Surveillance Procedure OSP-SW-M103 was to demonstrate the operability of the HPCS standby service water system per Technical Specification Surveillance Requirement 3.7.2.1. The licensee stated that the minimum acceptable flow value of 780 gpm was consistent with FSAR Table 9.2-5, "Standby Service Water Flow Rates and Associated Heat Loads Used in the Ultimate Heat Sink Analysis."

The team asked the licensee to determine if the minimum acceptable flow of 780 gpm allowed by Surveillance Procedure OSP-SW-M103 was less conservative than the flow value of 910 gpm assumed in Calculation ME-02-92-243 to develop the 40 percent heat transfer acceptance criterion. In response to this question, the licensee determined that the criterion was nonconservative and issued Problem Evaluation Report 298-0959, "DCW-HX-1C Thermal Performance Monitoring Acceptance Criteria was Non-conservative," dated July 30, 1998. This problem evaluation request determined that Heat Exchanger DCW-HX-1C, Diesel Generator DG-3, and the HPCS service water system were all operable because Heat Exchanger DCW-HX-1C had been cleaned in April 1996 and subsequent performance monitoring data had shown sufficient margin to ensure operability. In addition, the licensee reviewed the calculations and procedures for the remaining diesel generator heat exchangers and the RHR heat exchanger and found the acceptance criterion was correctly developed for these heat exchangers.

On August 10, 1998, the licensee provided the latest version of Problem Evaluation Report 298-0959, which documented their reportability evaluation. Based on a reanalysis of past thermal performance and operating data for Heat Exchanger DCW-HX-1C, the licensee determined that the heat exchanger had been capable of performing its design function at all times since performance monitoring began in 1990 and; therefore, the condition was not reportable. The problem evaluation report also included the licensee's plans for correcting the test acceptance criterion in Procedure PPM 8.4.63 prior to the next performance of the thermal performance test for Heat Exchanger DCW-HX-1C.

10 CFR Part 50, Appendix B, Criterion XI, "Test Control" states that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service was identified and performed in accordance with written test procedures, which incorporate the requirements and acceptance limits contained in applicable design documents. The 40 percent acceptance criterion specified in Calculation MWE-02-92-242 and developed in Calculation MWE-02-92-243 was not correctly determined from applicable design documents and as a result the thermal performance test did not assure that Heat Exchanger DCW-HX-1C would perform satisfactorily in service for all allowed HPCS standby service water flows. The failure to correctly develop the acceptance criterion from design documentation is a violation of 10 CFR Part 50, Appendix B, Criterion XI (50-397/9815-05).

The team determined that this inspection report adequately described the reasons for the violation, and the actions taken to correct and prevent recurrence of the violation. Therefore, no response to this violation is required.

c. Conclusions

The team concluded that, with the exception of the required flow for Heat Exchanger DCW-HX-1C, testing of the HPCS standby service water system demonstrated that the system was capable of providing an adequate cooling water supply to support operation of the HPCS system.

With regard to thermal performance testing of Division 3 Diesel Generator Heat Exchanger DCW-HX-1C, the licensee failed to effectively implement the test program control required to assure that the acceptance criteria of a surveillance test was valid for

all expected HPCS standby service water flows. This was determined to be a violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control." The licensee determined that the HPCS standby service water system and associated equipment were operable at all times since performance monitoring began in 1990.

E2.5 HPCS Instrument Calibration and Channel Check Procedures

a. Inspection Scope

The team evaluated the instrumentation and control configuration by walking down instrument racks for the HPCS related transmitters and process, and by reviewing related technical specification required channel calibration and channel functional test procedures.

b. Observations and Findings

The team reviewed instrument channel calibration and channel functional test procedures associated with HPCS setpoint calculations. Actual test results from the last 3 years for selected channels were also reviewed. The procedures were well written and had an adequate level of detail. The results were well documented. The team noted a few instances where the procedures were modified to clarify minor detail errors; this demonstrated an adequate level of a questioning attitude by instrument technicians and control room personnel as well as sensitivity to procedure adherence.

c. Conclusions

HPCS instrument setpoint channel check and calibration procedures were adequate to ensure safe and reliable operation. The procedures were well written and had an adequate level of detail.

E2.6 Division 3 Battery Testing

a. Inspection Scope

The team evaluated the testing of the Division 3 battery to verify that the capacity and surveillance testing of the Division 3 battery was adequate to assure that the battery was functional.

b. Observations and Findings

Division 3 Battery and Battery Charger Load Calculation

The team reviewed Calculation E/I-02-85-02,"High Pressure Core Spray Battery and Battery Charger," Revision 1, to evaluate the ability of the Division 3 battery to perform in accordance with its design accident load profile. The licensee had clearly established the size of all loads supplied by the battery, except two: the inrush current for spring charging motors of 4 kV breakers and the field flash current for Division 3 Diesel Generator. The licensee was not able to directly determine the size of these loads, so

they estimated their size, based on a combination of information from the nuclear steam supply system vendor, alternative calculations, and a review of data for comparable equipment. Considering the overall margin in the battery, this level of confirmation was acceptable.

Division 3 Battery Testing

The team reviewed the Performance Test Procedure ESP-B1DG3-F101 and the Service Test Procedure 7.4.8.2.1.19 for the Division 3 battery and determined that the licensee had elected to perform the performance test in lieu of the service test. However, the team noted that the performance test was not modified to envelope the service test during the initial minute of the battery's accident load profile as required by Technical Specification Surveillance Requirement 3.8.4.7.

In response to that concern, the licensee determined that the current performance tests for not only the Division 3 battery, but for the Division 1 and 2 Batteries E-B1-1 and E-B2-1 were also conducted in lieu of their respective service tests on April 30, 1998, May 12, 1998, and April 30, 1997 respectively. Since the performance tests were not modified to envelope the service test, the licensee now had to rely exclusively on the last service test for each of the three Class 1E batteries in order to determine their readiness for performance during an accident.

The licensee determined that the last service tests for Division 1, 2, and 3 batteries were performed on April 19. 1996, April 28, 1995, and May 9, 1996. Technical Specification 3.0.2 requires the next surveillance test to be performed at 1.25 times the interval stated in the technical specifications. Applying that criteria, the last service tests for each of the Division 1,2, and 3 batteries would expire on October 22, 1998, October 28, 1997, and November 19, 1998. The licensed determined that only the service test for Division 2 Battery E-B1-2 had expired prior to the performance of a qualified service test or its equivalent. The failure to perform a surveillance test that met the requirements of Technical Specification Surveillance Requirement 3.8.4.7 for Division 2 Battery E-B1-2 within 1.25 times the specified frequency of 24 months (prior to October 28, 1997) is a violation of Technical Specification 3.0.2 (50-397/9815-06).

The licensee informed the NRC of the expired tests on July 14, 1998, and asked for and was verbally granted a Notice of Enforcement Discretion on July 15, 1998, that permitted the licensee to delay taking any required actions until a technical specification amendment was approved. This allowed the licensee to wait until the R-14 refueling outage or an earlier outage of sufficient duration in order to perform a qualified service test for that battery.

Problem Evaluation Report 298-0887 was initiated to document this concern and identify all related corrective actions to be undertaken. On August 17, 1998, the licensee submitted Licensee Event Report (LER) 50-397/98-012-00, which discussed reportable corrective action taken, and action taken to preclude recurrence.

The team determined that the LER, in combination with this inspection report, adequately describes the reasons for the violation, and the actions taken to correct and prevent

recurrence of the violation. Therefore, the licensee was not required to respond to this violation.

c. Conclusions

The team confirmed the capacity of the Division 3 battery to perform its intended safety function and identified that the licensee had inappropriately credited a battery performance test for a service test. However, the previous service test had been conducted within the allowed frequency. During their review to identify other similar problems, the licensee identified that they had exceeded the allowed surveillance test frequency specified in Technical Specification 3.0.2 for the Division 2 Battery E-B1-2, a violation of NRC requirements. The team concluded that the licensee's extent of condition review was effective.

E2.7 Year 2000 Project

a. Inspection Scope

The team reviewed the status of the licensee's plan to assure safe plant operation at the turn of the century when computer chips and programs may malfunction due to an incorrect representation of the date.

b. Observations and Findings

The team found that the licensee did have a plan in place to address the year 2000 issue. Susceptible plant embedded systems had been identified and a detailed review of these systems was in progress. The licensee had already identified that some systems would require remediation. The licensee planned to benchmark their effort with other boiling water reactor utilities and develop contingency plans, where needed.

c. Conclusions

The licensee had a plan in place to address the year 2000 issue.

E7 Quality Assurance in Engineering Activities (37550)

E7.1 ECCS Pump 10 CFR 21 Evaluation

a. Inspection Scope (37550)

The team reviewed the licensee's response to a recent 10 CFR Part 21 report submitted by Ingersoll-Dresser Pump Company concerning breakage of cast iron pump suction heads. The NRC was notified of this potential safety hazard by the Ingersoll-Dresser Pump Company on July 9, 1998, in accordance with 10 CFR Part 21 (reference Event Notification 34499). The HPCS, LPCS, and RHR pumps were similar Ingersoll-Rand pumps with cast iron heads.

b. Observations and Findings

The team found that the licensee had addressed this issue prior to the 10 CFR Part 21 report in response to an industry event notice dated April 15, 1998. The industry report concerned the failure of a cast iron bearing support bracket in a RHR pump at Limerick Unit 1, discovered on April 11, 1998.

The licensee initiated Problem Evaluation Report 298-0407 on April 21, 1998. The problem evaluation report concluded that no inspections of the pumps were required at the time and that inspection of pump Nos. RHR-P-2A or 2B would be placed on the 5-year plan. In addition, a corrective action plan to inspect and/or replace the suction head on one of the RHR pumps was issued. These actions were based on the service history of the pumps and the recommendations provided by the pump vendor.

The team found the actions taken by the licensee to be appropriate and found that this issue had been addressed in a timely manner prior to the 10 CFR Part 21 report being issued.

c. Conclusions

The licensee effectively addressed this recent industry issue by evaluating the applicability of the condition in a timely manner and initiating an appropriate corrective action plan. The team found the licensee's response to this potential safety hazard to be both thorough and proactive.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Violation 50-397/9713-01: Inadequate Corrective Actions

a. Background

The NRC identified three examples of a 10 CFR Part 50, Appendix B, Criterion XVI violation. The licensee characterized the examples as either failure to promptly identify a condition adverse to quality or failure to fully implement corrective actions in a timely manner. The licensee attributed the violation to management not properly enforcing their expectations regarding timely identification and completion of corrective actions. In addition, the licensee stated that inadequate work management methods contributed to the untimely implementation of corrective actions.

b. Inspection Followup

The licensee corrected the specific examples, issued Problem Evaluation Report 298-0034 on January 12, 1998, and planned improved procedural guidance for management oversight of the corrective action process.

The team confirmed that the specific conditions had been corrected and reviewed the licensee's planned corrective actions for preventing recurrence and concluded that they were reasonable. The revision to Procedure PPM 1.3.12A was in progress at the time of

this inspection and was on schedule for completion on August 1, 1998. Based upon the licensee's corrective actions that were completed and scheduled to be completed, the team concluded that this violation was being properly addressed.

E8.2 (Closed) Violation 50-397/9713-02: Failure to Maintain Acceptance Criteria and Inservice Testing of RCIC System Valves

a. Background

The NRC identified the failure to maintain the acceptance criteria for the opening stroke-time testing of six RCIC system valves and the failure to maintain inservice testing of Valve RCIC-V-45 as required by 10 CFR 50.55a(f). The violation occurred as a result of an inappropriate RCIC system classification downgrade.

b. Inspection Followup

The NRC verified that the appropriate motor operated valves were included the licensee's IST program as the result of the RCIC System safety classification upgrade. The licensee determined this violation was caused by an inadequate safety evaluation. The preventive corrective action steps for this violation are identical to those for Apparent Violation 50-382/9713-03. The team's review of these actions is documented below in Section E8.3. The licensee achieved full compliance on December 18, 1997, when the licensee approved and incorporated changes to the IST program to properly reflect the safety classification of the RCIC components. The team concluded that this violation was properly addressed.

E8.3 (Closed) Violation 50-397/9713-03: Inadequate Safety Evaluation for RCIC Downgrade

a. Background

The NRC identified the failure to perform an adequate safety evaluation in accordance with 10 CFR 50.59. The licensee downgraded the RCIC system from a safety-related system to a nonsafety-related system without NRC approval. The NRC had previously verified that all pertinent RCIC components were upgraded by the licensee with the exception of two rupture discs on the RCIC turbine exhaust line.

b. Inspection Followup

The licensee agreed that it misapplied generic technical guidance in downgrading the RCIC system and had failed to identify an unreviewed safety question. During this inspection, the team confirmed that Work Order KKB9, Task 01, completed the replacement of RCIC turbine exhaust rupture discs, the last pertinent components requiring upgrade.

The licensee also reviewed past safety evaluations to identify similar violations. This review was documented in "Review of Approved 50.59 Safety Evaluations For the Use of Generic Guidance" dated 3/16/98. The licensee reviewed 911 safety evaluation summaries and 101 safety evaluations in order to determine if generic guidance appropriately applied. The licensee also revised Procedure PPM 1.3.43, "Licensing

Basis Impact Determinations," Revision 13, to clarify guidance for use and interpretation of generic documents and included this event in the licensing basis impact training outline for safety evaluation preparers and reviewers. This program upgrade was reviewed in NRC Inspection Report 50-397/98-13 and found to be satisfactory. Based on a review of the completed corrective actions, the team concluded that this violation was being properly addressed.

E8.4 (Closed) LER 98-005: Voluntary LER on RHR Valve Design Deficiency

a. Background

On April 23, 1998, a licensee engineering-review showed that discharge-to-radwaste Valve RHR-V-40 would not close upon receiving a manual close or isolation signal when throttled less then 13 percent open. This configuration was in conflict with the RHR system description as stated in the FSAR.

This four-inch motor-operated valve was used to throttle flow rate to radwaste from the suppression pool during normal operation and to initiate RHR, Loop B, shutdown cooling during shutdown. The valve provided a close safety function for secondary containment isolation and emergency cooling system lineup.

The LER documented several planned actions to correct the design deficiency and to prevent a recurrence of this type of problem for another valve.

b. Inspection Followup

The team verified that the licensee completed the corrective action identified in the LER.

The LER stated that the safety consequences of the design deficiency were minimal because the safety function is to close, the valve is normally closed, and the valve was in series with Valve RHR-V-49 that was unaffected by the design flaw. The probability of occurrence of Valve RHR-V-40 being open less than 13 percent coincident with a failure of Valve RHR-V-49 was very low. The team agreed with the licensee's conclusion that the safety consequences of the design deficiency were minimal.

10 CFR Part 50, Appendix B, Criterion III, "Design Control," states, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application, are correctly translated into specifications, drawings, procedures, and instructions.

FSAR Figure 7.3-14C included a wiring drawing for Valve RHR-V-40 that indicated that the valve would close as required upon initiation of an isolation signal. This design was not correctly translated into GE Functional Control Diagram CVI- 02E12-04.3.3,

Revision 8. As a result, Valve RHR-V-40 would not have closed or auto-closed if it was throttled open to between 9 to 13 percent. The failure to correctly translate the design specified in a license application into drawings is a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." The licensee properly identified and corrected this violation. This non-repetitive, licensee-identified, and corrected violation is being treated as a non-cited violation consistent with Section VII.B.1 of the NRC Enforcement Policy (50-397/9815-07).

E8.5 (Closed) Inspection Followup Item 50-397/9713-04: Potential for Numerous Calculation Modification Records to Affect Technical Content of Calculations.

a. Background

Calculation modification records were developed to postpone a calculation's revision until several design changes could be processed at one time. In NRC Inspection Report 50-397/96-201, the NRC reviewed Engineering Directorate Manual 2.15, "Preparation, Verification and Approval of Calculations," Revision 2, and noted that the procedure recommended that calculations be revised if five or more calculation modification records were outstanding against a calculation. The NRC found evidence that three sampled calculations had more than five calculation modification records outstanding and opened Unresolved Item 50-397/96201-16.

The NRC conducted a followup of the unresolved item and determined that the licensee's activities were in accordance with Procedure 2.15, in effect at the time, in that management approval was obtained when more than five calculation modification records were applied to a specific calculation. The inspectors also found that, as the result of this NRC finding, the licensee had strengthened informal management expectations for calculation modification record control and had established an engineering team to self-assess their calculation process and controls. The inspectors reviewed this self-assessment, which was completed on October 16, 1997. The inspectors noted that while the assessment identified numerous problems with the retrieving and handling of calculations and with Procedure 2.15, it did not determine, if it was necessary to verify the technical impact of the numerous calculation modification records on the content of the existing calculations.

The NRC reviewed a listing of calculations dated July 3, 1997, and found that 45 calculations had more than 5 calculation modification records. The NRC planned further inspection to evaluate the technical impact of an excessive number of calculation modification records.

b. Inspection Followup

The team found that in April 1998, the licensee implemented a prioritized plan to reduce the number of calculations with more than 5 calculation modification records from 45 to 13 by July 1999. The licensee stated that the remaining 13 calculations with more than five calculation modification records would be further reduced once the initial goal was attained.

HPCS Setpoint Calculation Modification Records

To assess the technical impact of multiple calculation modification records, the team reviewed the twelve unincorporated (plant implemented status) calculation modification records against various HPCS setpoint calculations. The team identified administrative and document control problems with four of them (Calculation Modification Records 92-0260, 92-0503, 92-0506, and 92-0546). In the worst case, these document control problems resulted in having two calculations of record with different setpoints for the Level 1 reactor vessel emergency core cooling system level switches and for the starting control for diesel driven air Compressor DSA-C-2C. However, the team did not find any evidence that these errors resulted in a plant procedure or hardware error. The licensee agreed to correct the administrative errors. These failures constitutes a violation of minor significance and are not subject to formal enforcement action.

Electrical Load Tally Calculation Modification Records

The team also reviewed calculation modification records associated with six calculations that analyze the loading on medium voltage and low voltage ac buses and one calculation for each of the three dc divisions that documented a similar analysis for the loads on the dc buses. The team found that the licensee used the calculation modification record process to track the addition of electrical loads to the busses.

Procedure EDP 2.15, "Preparation, Verification and Approval of Calculations," Revision 3, Step 4.5.5 stated that, "The CMR [calculation modification record] shall be prepared against the latest revision of the calculation and all outstanding CMRs against the calculation shall be considered. The pertinent outstanding CMRs, which could affect the results/conclusions, shall be identified and accounted for in the CMR."

The team found that, in general, the licensee was not specifically identifying the pertinent outstanding calculation modification records as required by Procedure EDP 2.15. The licensee was only recording that all CMRs for the particular CMR have been reviewed. To ensure that the intent of Procedure EDP 2.15 was implemented, the licensee established an informal computer-based system to track electrical load additions to the various electrical busses evaluated in Calculation E/I-02-90-01, "Low Voltage Systems Loading and Voltage Calculations, " Revision 4.

The team requested that the licensee review a selection of calculation modification records for Calculation E/I-02-90-01 to determine if the calculation's working file adequately addressed the bus loading. The licensee sampled 63 calculation modification records and determined that the calculation working file was not properly updated for the load additions described in the following three calculation modification records:

- CMR 92-0453, which increased the load amps on Panel PP-7A-A, circuit 18 by .04 amps;

- CMR 92-0489, which added a new load of 7.38 amps on Panel PP-8A-C-A; and

- CMR 97-0173, which increased the load amps on motor control center MC-8A for SW-V-12B from 5.75 amps to 5.9 amps.

The team concluded that use of the working file to track loads, did not meet the intent of EDP 2.15, Step 4.5.5, because all outstanding calculation modification records were not identified.

10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, "Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions." The team concluded that the licensee did not adhere to the requirements of Procedure EDP 2.15 in that the loads in all outstanding CMRs related to Calculation E/I-02-90-01 were not identified and accounted for. This failure is considered to be another example of a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," (50-397/9815-02).

Subsequently, the licensee added the loads described in these calculation modification records to the working file load tally and concluded that the affected motor control centers still met the acceptance criteria of the load calculation. The licensee also informed the team that, as a conservative practice, load deletions were not included in the working file, making the working file estimate conservative.

The licensee stated that they plan to develop written guidance for administering the working files.

The team concluded that use of numerous calculation records in lieu of making a formal revision to Calculation E/I-02-90-01 did affect the technical content of the calculation. However, the team also concluded that the licensee's working file process would adequately control load additions, if rigorously followed.

IV. Plant Support

F2 Status of Fire Protection Facilities and Equipment (64704)

a. Inspection Scope

The team conducted a fire protection equipment walk down with licensee personnel, interviewed fire brigade personnel, and conducted an independent walk down of selected areas to verify proper installation, operability, and maintenance of fire protection system and equipment. In addition, the team witnessed a fire drill conducted on the evening of July 29, 1998.

The team also reviewed 27 fire protection system surveillance procedures to determine if the fire protection equipment was being properly tested. The team reviewed the content

of these procedures and the frequency at which they were performed to ensure that the fire detection and suppression systems were tested in accordance with technical specification requirements. In addition, the team reviewed fire protection modifications to ensure that the fire protection equipment was being properly maintained and upgraded as needed.

b. Observations and Findings

The team's review of the fire protection system surveillances indicated that the licensee conducted the surveillances in accordance with their procedures and initiated appropriate work order tasks for any problems or discrepancies noted. The team noted that the surveillance procedures were consistent with technical specification requirements and performance frequencies. The team noted no discrepancies in the review of these surveillance procedures.

The team reviewed four fire protection modifications to assess the licensee's ability to maintain and upgrade the fire protection equipment over time. The following four modifications were reviewed:

- Technical Evaluation Report 94-0348, Revision 0, which installed a hanger to steady fire protection line at FP-V-642.
- Installation of muffler on Diesel Fire Pump 1, via Work Order Task ZP7401.
- Plant Modification Record 91-0379, Revision 0, Delete the Reactor Water Cleanup Room Fire Detection Sensors.
- Plant Modification Record 89-0427, Revision 0, Addition of Manual Pull Station in Service Building, Machine Shop.

Based on this review and a review of post modification test activities, the team concluded that the licensee was properly maintaining and upgrading the fire protection equipment.

The team interviewed several members of the licensee's fire brigade and found them to be knowledgeable in fire protection, fire fighting, and safe shutdown activities. The licensee's fire brigade consisted of a qualified fire brigade leader and at least four additional qualified fire brigade members on-site at all times. The team noted that the fire brigade was not included in the minimum shift crew complement required for unit shutdown. During the interviews, the fire brigade members informed the team that they maintained their medical certification by attending a yearly .nedical examination. The team considered the scheduling of these physical examinations was proactive in that fire brigade members were notified 45 days to 60 days prior to the examination date. Any fire brigade member who missed this examination was removed from the fire brigade until the medical examination was conducted.

Fire brigade members were required to participate in at least two fire drills each year. The team noted, during the records review, that the members participated in more than two fire drills each year. The team observed one fire drill conducted on the evening of July 29, 1998. The fire drill was conducted and monitored by fire protection personnel,

including the fire marshall. The team observed that the fire brigade was fully capable of mitigating the fire. The team observed a critique after the fire drill, conducted by the fire marshall. Based on these observations, the team determined that the fire drill was satisfactory and provided confidence that the fire brigade was properly trained.

The team reviewed the fire brigade training records on seven individuals who were currently qualified on the fire brigade. The team noted that these training records were complete and accurate.

The team conducted a walk down with the licensee of the essential fire fighting systems consisting of the fire pumps, piping systems, fire hose stations, fire detection systems, and fire barriers. During this walk down, the team noted that all fire pumps were operable, piping systems were painted and maintained in good condition, and that the fire hose stations were fully operable with tools attached for opening valves and attaching hoses. In addition, the team determined that the fire detection systems and fire barriers were operable. The team also conducted an independent walk down of selected areas in the plant, including the Division 2 Diesel Generator room. The team determined that fire extinguishers were inspected, charged, and pressurized for use and that transient combustibles were adequately controlled. The team noted that the fire detectors were operable and being properly maintained via surveillance procedures.

The NRC issued a Confirmatory Order modifying the WNP-2 License on March 25, 1998. This Confirmatory Order requires that Thermo-Lag barrier modifications be completed during the R14 refueling outage (Spring 1999) and that all modification package closeout be completed by December 1999. The licensee stated that the Thermo-Lag Reduction effort was not currently on schedule and were considering means to assure that the order requirements were met.

c. Conclusions

The team concluded that fire equipment was being properly tested at the required frequencies. No discrepancies were noted during a walk down of the fire protection system. Fire pumps, piping systems, and fire hose stations were being properly maintained. Fire detection systems were in service and fire extinguishers were being inspected and maintained ready for operation. Fire hose stations were also properly equipped and ready for use. The team also concluded that the fire protection equipment was being upgraded as necessary.

The fire brigade was properly trained and qualified to perform fire fighting, and the annual medical examination requirement was being met.

F3 Fire Protection Procedures and Documentation (64704)

a. Inspection Scope

The team reviewed procedures and documentation related to the fire protection program to evaluate the overall adequacy and implementation of the licensee's Fire Protection

Program. This review included seven procedures related to the licensee's approved Fire Protection Program.

b. Observations and Findings

The team reviewed procedures concerning the fire protection program implementation including control of transient combustibles, control of ignition sources, plant fire protection program implementation, and fire barrier impairment.

The introduction of transient combustibles into plant areas during routine operation and maintenance activities and the storage of combustibles in plant areas were governed by Procedure 1.3.10C, "Control of Transient Combustibles," Revision 0. This procedure delineated the responsibilities and procedural guidance for general combustible material control criteria, initiating transient combustible (TC) permits, extending TC permits, and clearing the TC permits. The team determined that this procedure was comprehensive for controlling transient combustibles. The installation of permanent combustible materials was controlled by the design control process.

The team determined that the control of ignition sources was governed by Procedure 1.3.10A, "Control of Ignition Sources," Revision 3. This procedure delineated the responsibilities and guidelines for the use of ignition sources. The team noted that the requirements for the uses of ignition sources were comprehensive. For example, the procedure identified what situations required a fire watch assignment, ensured that fire protection system impairments would be closed upon work completion, and ensured that a final inspection of the work area was performed upon termination of the fire watch and ignition source permit.

c. Conclusions

The team concluded that the fire protection program procedures were comprehensive in detailing the requirements for transient combustibles, barrier impairments, and control of ignition sources.

F7 Quality Assurance in Fire Protection Activities (64704)

a. Inspection Scope (64704)

The team reviewed the licensee's Quality Assurance activities in the fire protection program. These activities included the performance of periodic fire prevention/protection audits, the identification and resolution of fire protection discrepancies, the review of fire system/equipment changes and alterations, and the review of periodic surveillance activities to ensure that they were being conducted as required by the fire protection program.

The team reviewed two periodic audits conducted by the Quality Assurance Department. These were the 1998 Annual Fire Protection Audit and the 1997 Annual-Biennial-Triennial Audit.

b. Observations and Findings

The team reviewed the 1998 Annual Fire Protection Audit conducted during March 16 through March 31, 1998. This audit concluded that the fire protection program was being adequately implemented to meet the requirements and assure safety of the plant and personnel. The audit determined that the corrective actions taken with respect to fire protection related problems were evaluated and noted to be effective in preventing significant adverse trends. The fire fighting and protection training were judged to be adequate.

The team agreed with the 1998 Annual Audit findings. The team determined that the corrective action program with respect to fire protection was notable in that it prevented the recurrence of events. The audit determined that 65 problem evaluation requests were identified since January 1997 for fire protection issues. The audit then categorized the problem evaluation reports into groups of common problem types and reviewed them for increasing trends in the number and severity. The audit determined that there were no adverse trends.

During the audit review of problem evaluation reports, the licensee identified that several open corrective action items were over 1-year old. A detailed review of these older actions determined that the safety of the plant was not being compromised because of the age of these items. The licensee determined that the these items were in two categories: (1) equipment replacements being done on a planned schedule and (2) enhancements and clarifications to documentation. The audit determined that an average of three extensions had been granted with the oldest action item nearly 3 years old. The Quality Assurance Department initiated a Quality Recommendation 298-013-A to review the timeliness of open corrective actions. The fire protection manager reviewed the current list of fire protection corrective actions and provided a justification for each item. This review indicated that the scheduled dates were appropriate and that the risk of problem recurrence was negligible.

The team reviewed Quality Recommendation 298-013-A and the fire protection manager's response and determined that this action was appropriate.

The audit also included an assessment of the fire fighting and fire brigade training program and concluded that the training was adequate with no programmatic deficiencies. The most significant issue identified was that the fire brigade had not been recently trained on rope signals, hand signals, or shoulder tapping. The Quality Assurance Department issued Quality Recommendation 298-013-B, which recommended the addition of communications in fire brigade training.

In response to this issue, the fire department training manager revised the training lesson plans, classroom, and practical exercise training to include communications. The team verified that the revised training had included the use of communication skills.

The team reviewed the 1997 Annual-Biennial-Triennial Fire Protection Audit conducted May 22 through June 12, 1997, and determined that it was comprehensive and that it satisfied the requirements for assessing fire protection equipment and program

implementation requirements. The team agreed with the 1997 audit's findings. The 1997 audit identified strengths in the following areas:

- The training and commitment of fire protection personnel,
- The fire penetration seal program,
- Implementation and control of fire watch tours,
- Material condition of the fire fighting equipment, and
- Use of an independent consultant to conduct the fire program self assessment.

c. Conclusions

The team concluded that both Quality Assurance audits were comprehensive and satisfied the requirements for assessing fire protection equipment and program implementation requirements. The team agreed with the findings and recommendations of both audits. Several strengths identified in the 1997 audit by the licensee were confirmed by the team during this inspection, especially fire personnel knowledge and skill, and excellent material condition of the fire fighting equipment.

V. Management Meetings

X1 Exit Meeting Summary

The team met with licensee representatives on July 31, 1998, to conduct an exit interview. During this meeting, the team leader noted that team personnel had reviewed proprietary documentation during the course of the inspection. Proprietary documentation was not divulged in this report.

The licensee acknowledged the team's findings.

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

G. Barstas, I&C Design Engineer
R. Brownlee, Licensing Engineer
D. Beach, I&C Design Supervisor
D. Coleman, Regulatory Affairs Manager
R. Ehr, Lead Mechanical & Civil Engineer
M. Ferry, NSSS System Engineer
S. Ghbein, Project Engineer
R. Green, I&C Design Engineer
D. Mand, Manager, Design & Projects Engineering
L. Pong, Supervisor Performance Engineering
G. Richmond, I&C System Engineer
R. Seidl, I&C System Engineer
M. Schmidtz, NSS System Engineer

NRC

S. Boynton, Senior Resident Inspector

INSPECTION PROCEDURES USED

64704	Fire Protection
37550	Engineering
92903	Followup - Engineering
93809	Safety System Engineering Inspection (SSEI)

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-397/9815-01	VIO	The design basis for CST capacity and reactor vessel water Level 1 was not correctly translated into the plant design and the Technical Specifications respectively (Sections E1.1.1 and E1.2).

50-397/9815-02	VIO	Procedures were not adequately followed or established for marking Category 1 and 2 PAM instruments, verifying short circuit calculation assumptions and controlling calculation modification records (Sections E1.2, E1.3 and E8.5).
50-397/9815-03	VIO	A dc breaker coordination design deficiency was not promptly corrected (Section E1.3).
50-397/9815-04	URI	The establishment of appropriate leak testing for liquid secondary containment bypass valves requires NRC review of the method for calculating release fraction (Section E2.3)
50-397/9815-05	VIO	The thermal performance test acceptance criterion for the Division 3 Diesel Generator Heat Exchanger DCW-HX-1C was not valid for all expected HPCS standby service water flows (Section E2.4).
50-397/9815-06	VIO	Surveillance Requirement 3.8.4.7, the Division 2 Battery service test, was not completed within the specified frequency as required by Technical Specification 3.0.2 (Section E2.6).
50-397/9815-07	NCV	The requirement for Valve RHR-V-40 to close for secondary containment isolation and to establish the emergency cooling system lineup specified in the FSAR was not correctly translated into drawings (Section E8.4).

Closed

50-397/9713-01	VIO	Inadequate Corrective Actions (Section E8.1).
50-397/9713-02	VIO	Failure to Maintain Acceptance Criteria and Inservice Testing of RCIC System Valves (Section E1.2).
50-397/9713-03	VIO	Inadequate Safety Evaluation for RCIC Downgrade (Section E1.3).
50-397/9713-04	IFI	Potential for Numerous Calculation Modification Records to Affect Technical Content of Calculations (Section E8.5).
50-397/98-005	LER	Voluntary LER on RHR Valve Design Deficiency (Section E8.4).
50-397/9815-03	VIO	A dc breaker coordination design deficiency was not promptly corrected (Section E1.3).

50-397/9815-05	VIO	The thermal performance test acceptance criterion for the Division 3 Diesel Generator Heat Exchanger DCW-HX-1C was not valid for all expected HPCS standby service water flows (Section E2.4).
50-397/9815-06	VIO	Surveillance Requirement 3.8.4.7, the Division 2 battery service test, was not completed within the specified frequency as required by Technical Specification 3.0.2 (Section E2.6).
50-397/9815-07	NCV	The requirement for Valve RHR-V-40 to close for secondary containment isolation and to establish the emergency cooling system lineup specified in the FSAR was not correctly translated into drawings (Section E8.4).

LIST OF ACRONYMS USED

ac	alternating current
CFR	Code of Federal Regulations
CMR	calculation modification record
CST	condensate storage tank
dc	direct current
DG	diesel generator
ECCS	emergency core cooling system
FSAR	Final Safety Analysis Report
gpm	gallons per minute
HFES	human factors engineering standard
HPCS	high pressure core spray
IFI	inspection followup item
LER	licensee event report
LOCA	loss-of-coolant accident
LPCI	low pressure coolant injection
LPCS	low pressure core spray
MOV	motor operated valve
NPSH	net positive suction head
PER	problem evaluation request

PMR	plant modification request
psi	pounds per square inch
psia	pounds per square inch absolute
psid	pounds per square inch differential
psig	pounds per square inch gage
RCIC	reactor core isolation cooling
RHR	residual heat removal system
SBLOCA	small break loss-of-coolant accident
scfh	standard cubic feet per hour
SSEI	safety system engineering inspection
TS	Technical Specification
URI	unresolved item
USQ	unreviewed safety question
VIO	violation

DOCUMENTS REVIEWED

SAFETY EVALUATIONS

NUMBER	DESCRIPTION	REVISION
95-101	FSAR Section 6.2, Containment Systems	December 13, 1995
97-087-0	Basic Design Change BDC-96-0139-0A	March 19, 1998

PROBLEM EVALUATION REPORTS

NUMBER	DESCRIPTION	REVISION
298-0928	FSAR Value for Secondary Containment Bypass Leakage Limit is Inappropriately being Applied to Liquid Leakage Bypass Paths	July 28, 1998 (Draft)
298-0407	OER per INPO Network Operating Event OE8933, RHR Pump Bearing Support Bracket Failure	April 21, 1998
298-0899	Results of Calculation E/I-02-91-1011 (HPCS-LS-1A, -1B) Not Incorporated into Calculation 5.52.070 (CST Setpoints)	July 17, 1998

PROBLEM EVALUATION REPORTS

NUMBER	DESCRIPTION	REVISION
298-0959	DCW-HX-1C Thermal Performance Monitoring Acceptance Criteria is Non-Conservative	July 30, 1998
292-0409	Inadequate Coordination Identified in Calculation E/I-02-91-07	Revision 0
298-0034	Permanent Corrective action	Revision 1
298-0421	Potential for RHR-V-40 To Not close if Throttled Partially Open	Revision 0
298-0887	125 Volt Division 2 Battery E-B1-2 Surveillance SR 3.8.4.7 Was Not Adequately Performed	Revision 0
298-0961	Timely Completion of Corrective Action Associated with PER 292-0409	Revision 0
298-0985	Plant Modification Record (PMR) 86-0362-0 Implementation Omitted Revising Voltage Drop Calculation 2.07.04 for DLO-M-P/10	Revision 0

PROCEDURES

NUMBER	DESCRIPTION	REVISION
5.5.13	Overriding HPCS High RPV Level Isolation Interlock	Revision 4
4.4.4.2	Inadvertent HPCS Startup	Revision 9
2.4.4	High Pressure Core Spray System	Revision 20
2.4.5	Standby Service Water System	Revision 38
7.4.7.1.1.3	HPCS Service Water Valve Position Verification (Data from May 17, 1996)	Revision 12
OSP-SW-M103	HPCS Service Water Valve Position Verification (Data from June 16, 1997)	Revision 0
OSP-SW-M103	HPCS Service Water Valve Position Verification (Data from May 12, 1998)	Revision 2
8.4.63	Thermal Performance Monitoring of DCW-HX-1C (Data from February 23, 1998; March 14, 1997; and February 12, 1998)	Revision 5
SAG-1	Severe Accident Guidelines	Revision 0

PROCEDURES

NUMBER	DESCRIPTION	REVISION
SAG-2	Severe Accident Guidelines	Revision 0
5.1.1	RPV Control	Revision 13
5.1.2	RPV Control - ATWS	Revision 14
5.1.3	Emergency RPV Depressurization	Revision 15
5.1.4	RPV Flooding	Revision 5
5.1.5	Emergency RPV Depressurization - ATWS	Revision 3
5.1.6	RPV Flooding - ATWS	Revision 3
5.2.1	Primary Containment Control	Revision 12
5.3.1	Secondary Containment Control	Revision 13
5.4.1	Radioactivity Release Control	Revision 11
5.6.1	Station Blackout (SBO)	Revision 5
OSP-HPCS/IST-Q701	HPCS System Operability Test	Revision 3
OSP-SW/IST-Q703	HPCS Service Water Operability	Revision 1
OSP-HPCS/IST-R701	HPCS Check Valve Operability - Refueling Shutdown	Revision 1
TSP-RV/IST-R701	Testing of IST Program Safety/Relief Valves	Revision 1
2.8.6	Condensate Storage and Transfer System	Revision 12
2.7.3	High Pressure Core Spray Diesel Generator	Revision 31
4.601.A1	601.A1 Annunciator Panel Alarms	Revision 11
7.4.7.1.2B	HPCS Service Water Flow Balance (Data from June 13, 1993; December 27, 1993; March 24, 1994; June 14, 1994; March 22, 1995; April 1, 1995; and May 23, 1995)	Revision 0
OSP-SW-M103	Standby Service Water Loop A Valve Position Verification	Revision 4
OSP-SW-M102	Standby Service Water Loop B Valve Position Verification	Revision 2
SWP-FPP-01	Nuclear Fire Protection Program	Revision 0
PPM 1.3.10	Plant Fire Protection Program Implementation	Revision 21

PROCEDURES

NUMBER	DESCRIPTION	REVISION
PPM 1.3.10A	Control of Ignition Sources	Revision 3
PPM 1.3.10B	Active Fire System Op. and Impairment Control	Revision 1
PPM 1.3.10C	Control of Transient Combustibles	Revision 0
PPM 1.3.19	Plant Material Condition Inspection Program	Revision 23
PPM 1.3.57	Barrier Impairment	Revision 11
PPM 15.1.1	Fire Suppression Systems Inspection	Revision 8
PPM 15.1.2	Fire Door Operability	Revision 10
PPM 15.1.3	FP-P-1 Monthly Operability Test	Revision 9
PPM 15.1.4	FP-P-110 Monthly Operability Test	Revision 9
PPM 15.1.5	FP-P-2A Monthly Operability Test	Revision 4
PPM 15.1.6	FP-P-2B Monthly Operability Test	Revision 4
PPM 15.1.14	Pre-action and Deluge Systems Flow Switch	Revision 6
PPM 15.1.15	Wet Pipe Sprinkler Flow Switch Functional Test	Revision 9
PPM 15.1.16	Protected Area Suppression Systems Inspection	Revision 3
PPM 15.1.18	Quarterly Fire Suppression Systems Valve Align.	Revision 9
PPM 15.1.19	Fire Protection System Annual Flowpath Valve Exer.	Revision 8
PPM 15.1.20	Pre-action Systems Trip Test	Revision 8
PPM 15.1.23	Protected Area & Warehouse Sprinkler Sys. Test	Revision 4
PPM 15.2.1	Monthly Fire Pump Battery Testing	Revision 5
PPM 15.2.2	Function and Sensitivity Check of Ionization Detect.	Revision 7
PPM 15.2.6	HVA C Duct Detectors-Channel Functional Test	Revision 7
PPM 15.2.7	Zone 22, 23, 25, and 26 HVAC Duct Smoke Detect.	Revision 4
PPM 15.2.14	Function Check, Sensitivity Check and Cleaning of Photoelectric Detectors	Revision 4
PPM 15.2.16	Thermal Detectors-Channel Functional Check	Revision 4

PROCEDURES

NUMBER	DESCRIPTION	REVISION
PPM 15.2.25	Manual Pull Stations-Channel Functional Check	Revision 5
PPM 15.3.5	Fire Damper Operational Inspection	Revision 7
PPM 15.3.7	Fire Systems Inspection	Revision 5
PPM 15.3.9	Fire Pump Drive Inspection FP-ENG-1	Revision 6
PPM 15.3.10	Fire Pump Drive Inspection FP-ENG-110	Revision 3
PPM 15.3.13	Interior Deluge Systems Trip Test and Air Flow Test	Revision 5
PPM 15.3.14	Exterior Deluge Systems Trip Test and Strainer Flush	Revision 7
PPM 15.4.6	Fire Rated Pene. Seal & Structural Fire Barrier Operability Inspection	Revision 4
PPM 1.3.43	Licensing Basis Impact Determinations	Revision 13
MMP-DG3-B103	Diesel Generator DG-3 Mechanical Inspection	Revision 1
TSP-DG3/LOCA-B501	HPCS Diesel Generator DG3 LOCA Test	Revision 0

CALCULATIONS

NUMBER	DESCRIPTION	REVISION
5.19.13	Sizing of HPCS Emergency Water Volume	Revision 5
CMR-94-1160	Calculation Modification Record for Calculation 5.19.13, Revision 5	December 19, 1994
CMR-97-0003	Calculation Modification Record for Calculation 5.19.13, Revision 5	April 17, 1997
NE-02-90-50	HPCS System Analysis	Revision 1
E/I-02-91-1018	Setting Range Determination for Instrument Loops: HPCS-LS-3A and HPCS-LS-3B	Revision 0
CMR-94-1162	Calculation Modification Record for Calculation E/I-02-91-1018, Revision 0	November 16, 1994
E/I-02-91-1011	Setting Range Determination for Instrument Loops: HPCS-LS-1A and HPCS-LS-1B	Revision 0
CMR-96-0007	Calculation Modification Record for Calculation E/I-02-91-1011, Revision 0	January 15, 1996

CALCULATIONS

NUMBER	DESCRIPTION	REVISION
5.52.070	Setpoints - CST System	Revision 0
ME-02-82-03-0	Strainer Plugging Due to Containment Coating in Suppression Pool Post-LOCA	Revision 0
CMR-91-0110	Calculation Modification Record for Calculation ME-02-82-03-0, Revision 0	May 2, 1991
ME-02-90-17	Pressure Drop Verification for HPCS System	Revision 0
CMR-98-0179	Calculation Modification Record for Calculation ME-02-90-17, Revision 0	July 23, 1998
5.19.11	High Pressure Core Spray System - Pressure Drop Calculations	Revision 4
CMR-94-0142	Calculation Modification Record for Calculation 5.19.11, Revision 4	May 4, 1994
CMR-96-0225	Calculation Modification Record for Calculation 5.19.11, Revision 4	July 23, 1996
CMR-97-0115	Calculation Modification Record for Calculation 5.19.11, Revision 4	July 18, 1997
NE-02-82-44	Suppression Pool Temperature Versus Pump Flows of HPCS, LPCS, RCIC and RHR Systems	Revision 0
ME-02-96-21	MOV Pressure Locking Calculation	Revision 0
C106-92-03.02	WNP-2 HPCS System MOV Design Basis Review	Revision 2
5.19.08	High Pressure Core Spray System - Restrictors	Revision 0
10.04.72	WPPSS NP #2 Analysis Vortex Formation at the HPCS/RCIL Suction Inlets in the Condensate Storage Tanks	Revision 0
5.19.14	NPSH of HPCS Pump - Maximum Allowable Suppression Pool Temperature.	Revision 0
5.19.10	High Pressure Core Spray System - ECCS Minimum NPSH Calculations - Reg. Guide 1.1, Rev. 0	Revision 0

CALCULATIONS

NUMBER	DESCRIPTION	REVISION
CMR-94-0229	Calculation Modification Record for Calculation 5.19.10, Revision 0	April 27, 1994
CMR-95-0692	Calculation Modification Record for Calculation 5.19.10, Revision 0	November 14, 1995
CMR-96-0227	Calculation Modification Record for Calculation 5.19.10, Revision 0	July 23, 1996
CMR-97-0207	Calculation Modification Record for Calculation 5.19.10, Revision 0	July 18, 1997
NE-02-83-09	LI QSS - HPCS System Flow Recirculation	Revision 0
ME-02-92-243	DCW-HX-1C Design Performance Requirements	Revision 0
ME-02-92-242	DCW-HX-1C Performance Evaluation	Revision 0
ME-02-92-243	DCW-HX-1C Design Performance Requirements	Revision 0
NE-02-89-25	Vortex Limit at Intake Strainer of Pump for HPCS, LPCS, RCIC, and RHR Systems	Revision 1
ME-02-91-26	HPCS Test Line Orifice Installation	Revision 0
CMR-91-0162	Calculation Modification Record for Calculation ME-02-91-26, Revision 0	June 19, 1991
CMR-92-0469	Calculation Modification Record for Calculation ME-02-91-26, Revision 0	November 2, 1992
8.14.64B	HPCS System M200 Sht 100 & 132 AG 68 Piping Analysis	Revision 10
ME-02-92-244	Minimum Heat Transfer Required for DCW Heat Exchangers A & B	Revision 0
CMR-94-1104	Calculation Modification Record for Calculation ME-02-92-244, Revision 0	November 9, 1998
ME-02-92-245	RHR Heat Exchanger Tube Side Flowrate and Inlet Temperature Evaluation	Revision 0
CMR-97-0010	Calculation Modification Record for Calculation ME-02-92-245, Revision 0	January 14,1998
E/I-02-85-02	High Pressure Core Spray Battery and Battery Charger	Revision 1

CALCULATIONS

NUMBER	DESCRIPTION	REVISION
E/I-02-91-06	Short Circuit Calculation for the 250V, 125V, and 24 V D.C. Systems	Revision 0
E/I-02-92-01	Fuse Coordination Study for DC Power Distribution Systems	Revision 0
E/I-02-87-07	WNP-2 Plant Main Bus Voltage Calculation	Revision 3
E/I-02-90-01	Low Voltage Systems Loading and Voltage Calculations	Revision 4
E/I-02-95-01	Overcurrent Protective Device Settings and Coordination Calculations for 480 Volt Distribution Systems	Revision 0
2.07.04	D.C. Cable Voltage Drop	Revision 5
2.12.58	2nd Level Undervoltage Relay Settings for Buses SM-7, SM-8, and SM-4	Revision 4
ME-02-92-74	Calculation for Thrust & Setpoint for HPCS Motor Operator Valve 1	Revision 0
ME-02-92-75	Calculation for Thrust & Setpoint for HPCS Motor Operator Valve 4	Revision 0
ME-02-92-78	Calculation for Thrust & Setpoint for HPCS Motor Operator Valve 12	Revision 1
ME-02-92-79	Calculation for Thrust & Setpoint for HPCS Motor Operator Valve 15	Revision 2
ME-02-92-80	Calculation for Thrust & Setpoint for HPCS Motor Operator Valve 23	Revision 0
ME-0292-234	On Site Diesel Fuel Storage for the Emergency Diesel Generators DG-1, DG-2, and DG-3.	Revision 0
E/I-02-93-04	Overcurrent Protection of Primary containment Electrical Penetrations	Revision 2
E/I-02-91-03	Div.1, Div. 2, and Div. 3 Diesel Generator Loading Calculations	Revision 6

CALCULATIONS

NUMBER	DESCRIPTION	REVISION
02.06.20	Cable Ampacity Verification Calculations for Conduit & Tray	Revision 3
E/I-02-87-02	480V MCC Load Data for LOCA Operation	Revision 6
E/I-02-86-05	6.9KV, 4.16KV, and 480V Motor Load Data for Normal Full Load Operation	Revision 4
E/I-02-85-07	480V MCC Load Data for Normal Full Load Operation	Revision 10
E/I-02-87-03	4.16KV and 480V Motor Load Data for LOCA Operation	Revision 2
E/I-02-92-13	Short Circuit Current Calculation for 480V Systems	Revision 0
E/I-02-92-09	Short Circuit Current Calculation for 4.16 and 6.9 KV Buses	Revision 0
E/I-02-85-08	Generators, Transformers, and Branch Data for WNP-2 Distribution Systems	Revision 7

DESIGN CHANGES

NUMBER	DESCRIPTION	REVISION
BDC No. 96-0139-0A	ECCS Suction Strainer Replacement	Revision 0

LICENSING DOCUMENT CHANGE REQUESTS

NUMBER	DESCRIPTION	REVISION
95-072	SAR/Technical Specification Basis Change Notice Form - FSAR 6.2.3.2, 6.2.3.3.2, Table 6.2-16, 15.6.5.5.1.2, and 312.017	Revision 0

DRAWINGS

NUMBER	DESCRIPTION	REVISION
Drawing M520	Flow Diagram HPCS and LPCS Systems - Reactor Building	Revision 83

Drawing M527	Flow Diagram Condensate Supply System - All Buildings	Revision 90
Drawing M524, Sheet 1	Flow Diagram Standby Service Water System - Reactor, Radwaste, D.G. Buildings and Yard	Revision 96
Drawing D-220-3500-070.0 COND-LT40, Sheet 3	Local Instrument Installation Storage Tank Area El 441'-0" COND-LT40	Revision 1

MISCELLANEOUS DOCUMENTS

NUMBER	DESCRIPTION	REVISION
Audit 298-013	WNP-2 Annual Fire Protection Audit- 1998	Revision 0
Audit 297-040	WNP-2 Annual-Biennial-Triennial Audit-1997	Revision 0
Technical Evaluation Report 94-0348	Hanger installation Fire Protection Line FP-V-642	Revision 0
Surveillance Report 297-054	Diesel Fire Pump #1 Muffler Replacement	Revision 0
Plant Modification Record 91-0379	Delete RWCU Room Fire Detection Sensors	Revision 0
Plant Modification Record 89-0429	Addition of Manual Pull Station in Service Building, Machine Shop	Revision 0
PTL No. 135936	Operating Experience Report Disposition Form - IEN96055 - Inadequate Net Positive Suction Head of Emergency Core Cooling and Containment Heat Removal Pumps under Design Basis Accident Conditions	January 13, 1997
Letter GO2-98-002	90-Day Response to Generic Letter 97-04 - WNP2 to NRC	January 5, 1998
Letter GO2-96-199	Request for Amendment to Secondary Containment and Standby Gas Treatment System Technical Specifications - WNP2 to NRC	October 15, 1996

MISCELLANEOUS DOCUMENTS

NUMBER	DESCRIPTION	REVISION
OER Action Tracking No. 81032H	Operating Experience Review Summary - IEN91056 - Potential Radioactive Leakage to Tank Vented to Atmosphere	October 24, 1991
23A1619AA	General Electric Design Specification Data Sheet - High Pressure Core Spray System	Revision 12
RP03	IST Program Plan Relief Request	Revision 1
FSAR Section 6.2	Containment Systems	Amendment 52
TM-2099	Technical Memorandum - Secondary Containment Bypass Leakage	Revision 0
Technical Specification 3.5	Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System	Amendment 150
Technical Specification Basis 3.5	Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System	Revision 7
PER No. 294-0074	Follow-up Assessment of Operability - The Presence of High Pressure Trapped between the Valve Seats Could Lock the Valves in the Closed Position and Prevent the Valves from Performing their Opening Safety Functions.	June 17, 1997
Section 308	Design Specification for High Pressure Core Spray System	Revision 4
82-RSY-0900-T3	License Training System Description for High Pressure Core Spray System	Revision 8
Letter GO2-97-218	Request for Amendment to Secondary Containment and Standby Gas Treatment System Technical Specifications (Additional Information) - WNP2 to NRC	December 4, 1997
Letter GI2-90-009	Evaluation of JCO Regarding Standby Gas Treatment System Attainment of Secondary Containment Pressure (TAC No. 75048) - NRC to WNP2	January 3, 1990
SS2-PE-89-0646	Interoffice Memorandum - Potential Bypass Leakage and Unmonitored Effluent Paths	June 22, 1989

MISCELLANEOUS DOCUMENTS

NUMBER	DESCRIPTION	REVISION
82-RSY-1400-T3	License Training System Description for Standby Service Water System	Revision 9
7.4.5.1.11	Record of Reference Values and Acceptance Criteria Changes for ASME Pumps and Valves	April 20, 1992
IST Program Plan	IST Program Plan - 2nd 10-Year Interval	Revision 1
Division 60	Design Specification for Reactor Core and System Analysis for WNP-2	Revision 9
FSAR Figure 6.3-1	Head Versus High Pressure Core Spray Flow Used in LOCA Analysis	Amendment 51
FSAR Section 15.6.5.5.1.2	Fission Product Transport to the Environment	Amendment 30
Technical Specification 3.7.1	Standby Service Water (SW) System and Ultimate Heat Sink (UHS)	Amendment 149
Section 309	Design Specification for Standby Service Water System	Revision 2
FSAR Section 6.3.2.2.1	High Pressure Core Spray (HPCS) System	Amendment 51
FSAR Table 9.2-5	Standby Service Water Flow Rates and Associated Heat Loads Used in the Ultimate Heat Sink Analysis	Amendment 52
LER 98-005	Potential for Failure of Residual Heat Removal System Valve to Close on an Isolation Signal	Revision 0
WOT KKB9, Task 01	MMP-RCIC/IST-F701 RCIC-RD-1 and RCI	May 1, 1998
WNP-2 Document	Review of Approved 50.59 Safety Evaluations for the Use of Generic Guidance Final Report	3/16/98
WOT LFF6, Task 01	RHR-MO-40 Install Modification	5/22/98
WNP-2 Document	IST Program Plan - 2nd 10-Year Interval (Pages 94,95,96, and 96a)	Revision 1

MISCELLANEOUS DOCUMENTS

NUMBER	DESCRIPTION	REVISION
WNP-2 Document ESOOOOO8	Licensing Basis Impact Determination Update Training - Presentation Guide	Revision 4