April 18, 2003

Mr. A. Cayia
Site Vice-President
Point Beach Nuclear Plant
Nuclear Management Company, LLC
6610 Nuclear Road
Two Rivers, WI 54241

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 50-266/03-02; 50-301/03-02

Dear Mr. Cayia:

On March 31, 2003, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Point Beach Nuclear Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on April 1, 2003, with you and members of your staff.

The inspection examined activities conducted under your license as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the NRC has identified four issues that were evaluated under the risk significance determination process as having very low risk significance (Green). Two of those issues were determined not to involve a violation of NRC requirements. The remaining two issues were determined to involve violations of NRC requirements. However, because both violations were non-willful and non-repetitive and because they were entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 801 Warrenville Road, Lisle, IL 60532-4351; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Point Beach Nuclear Plant facility.

The NRC also identified two findings for which the final risk significance remains to be determined at a later date. The first finding concerned the effects of prolonged water submergence on 13.8-kilovolt, 4160-volt, and 480-volt electrical distribution cables. The second finding concerned the emergency preparedness program and pertained to 10 CFR Part 50.54(q) screenings and the configuration control and replacement of emergency response facility communications equipment. Neither of these findings presented an immediate safety concern.

Since the terrorist attacks on September 11, 2001, the NRC has issued two Orders (dated February 25, 2002, and January 7, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. The NRC also issued Temporary Instruction 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures required by the February 25th Order. Phase 1 of Temporary Instruction 2515/148 was completed at all commercial nuclear power plants during 2002, and the remaining inspections are scheduled for completion in 2003. Additionally, table-top security drills were conducted at several licensees to evaluate the impact of expanded adversary characteristics and the interim compensatory measures on licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Security and Incident Response. For 2003, the NRC will continue to monitor overall safeguards and security controls, conduct inspections, and resume force-on-force exercises at selected power plants. Should threat conditions change, the NRC may issue additional Orders, advisories, and temporary instructions to ensure adequate safety is being maintained at all commercial power reactors.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Kenneth Riemer, Chief
Branch 5
Division of Reactor Projects

Docket Nos. 50-266; 50-301
License Nos. DPR-24; DPR-27

Enclosure: Inspection Report 50-266/03-02; 50-301/03-02

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REGION III

Docket Nos:	50-266; 50-301
License Nos:	DPR-24; DPR-27
Report No:	50-266/03-02; 50-301/03-02
Licensee:	Nuclear Management Company, LLC
Facility:	Point Beach Nuclear Plant, Units 1 & 2
Location:	6610 Nuclear Road Two Rivers, WI 54241
Dates:	December 29, 2002, through March 31, 2003
Inspectors:	P. Krohn, Senior Resident Inspector M. Morris, Resident Inspector R. Schmitt, Radiation Specialist T. Madeda, Physical Security Inspector
Approved by:	Kenneth Riemer, Chief Branch 5 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000266-03-02, IR 05000301-03-02; Nuclear Management Company, LLC; on 12/29/02-03/31/03, Point Beach Nuclear Plant; Units 1 & 2. Personnel Performance During Non-Routine Evolutions, Post-Maintenance Testing, and Identification and Resolution of Problems.

This report covers a 3-month period of baseline resident inspection, an announced baseline radiation protection inspection, and regional physical security inspection reviews. The inspections were conducted by a regional radiation specialist inspector, a regional physical security inspector, and the resident inspectors. Two Non-Cited Violations (NCVs), three Green findings, and two findings with significance to be determined were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspection Findings

Cornerstone: Mitigating Systems

To Be Determined. Units 1 and 2. The inspectors identified an Unresolved Item (URI) concerning the effects of prolonged water submergence on 13.8-kilovolt, 4160-volt, and 480-volt electrical cables. The actual physical condition, deterioration rates, remaining service life, cable insulation trend predictions, effects of repeated freezing and thawing cycles, potential electrical breaker coordination impacts, cable splice location, potential for collapsed underground conduits, and worse case failure analyses were identified as areas requiring further NRC review.

The inspectors determined that the issue was more than minor because: 1) it affected the cornerstone objective of limiting the likelihood of those events that upset plant stability during shutdown as well as power operations; and 2) if left uncorrected, would become a more significant safety concern in subsequent years if cable degradation were to interrupt the continuity of offsite power to the safeguards electrical buses. The issue did not represent an immediate safety concern and was considered a URI Item pending further regulatory review. (Section 1R15.1)

Green. Units 1 and 2. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requirements for inadequate emergency diesel generator (EDG) safety-related protective relay calibration procedures which contained quantitative acceptance criteria limits that did not correspond to vendor recommended values. The primary cause of this finding was related to the cross-cutting area of human performance. Despite multiple opportunities for procedure writers, technical reviewers, relay technicians, maintenance work planners, electrical maintenance first-line supervisors, and operations personnel to have identified these errors, each of the four procedures used to calibrate the EDG safety-related protective relays were found to contain similar quantitative acceptance criteria errors.

This finding was more than minor because it: 1) affected the mitigating systems cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events, and 2) if left uncorrected, would become a more significant safety concern in subsequent years if out-of-specification EDG safety-related protective relay settings affecting equipment operability and electrical distribution system coordination were left in service and not corrected. The finding was determined to be of very low risk significance since the inadequate procedures did not result in a design or qualification deficiency, an actual loss of the safety function, or involve internal or external initiating events. (Section 1R19.1)

Green. Units 1 and 2. The inspectors identified a finding of very low risk significance finding concerning the return to service of the G-05 gas turbine (GT) generator prior to completion of troubleshooting efforts involving starting diesel oil samples and certain maintenance activities. The primary cause of this finding was related to the cross-cutting area of human performance in that lack of interdepartmental communications and coordination caused the GT to be inappropriately returned to service on March 3, 2003, despite starting diesel analyses that indicated advanced oil degradation and the onset of bearing damage and no return-to-service testing requirements having been defined in the maintenance department troubleshooting plan.

The inspectors determined that the issue was more than minor because it affected the availability, reliability, and capability of the G-05 GT, a mitigating system. The finding was of very low safety significance since the inappropriate return-to-service did not result in a design or qualification deficiency, an actual loss of the safety function, or involve internal or external initiating events. No violation of NRC requirements occurred. (Section 1R19.2)

Green. Units 1 and 2. A Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” was identified through a self-revealing event on February 11, 2003, when one of the main control board indications associated with Unit 1 ‘B’ main steam line pressure began reading higher that the other two. The higher pressure indicated the formation of an ice plug associated with pressure transmitter 1PT-483, a transmitter providing input to the engineering safeguards system. The primary cause of this finding was related to the cross-cutting area of human performance in that lack of facade freeze protection system coordination and training in the areas of lagging deficiencies and facade freeze system operations resulted in the removal of one of the three main steam line pressure inputs to the engineering safeguards system, a system relied upon to mitigate the consequences of a design basis accident.

The inspectors determined that the facade freeze protection issues were more than minor because: 1) they had affected the availability, reliability, and capability of an input to the engineering safeguards system, a system relied upon to mitigate the consequences of a design basis accident; and 2) if left uncorrected, they would become a more significant concern in subsequent years if freezing of sensing lines resulted in the inability to mitigate the consequences of an accident. The finding was determined to be of very low risk significance since the facade freeze protection issues did not result in a design or qualification deficiency, an actual loss of the safety function, or meet any of the internal or external event screening criteria. (Section 4OA2.1)

Cornerstone: Emergency Preparedness

Green. Units 1 and 2. The inspectors identified one finding of very low risk significance for not having adequate configuration control and not providing sufficient drawings and instructions to maintenance and operations personnel during an emergency notification telephone system battery charger failure and subsequent replacement activities. The primary cause of this finding was related to the cross-cutting area of human performance in that a lack of understanding of the basic system configuration and the absence of associated drawings and operating instructions resulted in unnecessary periods of system unavailability.

The inspectors determined that the issue was more than minor because: 1) it affected the emergency preparedness cornerstone equipment and communications system attribute, and 2) if left uncorrected, would become a more significant safety concern if emergency response facility communication system modifications were made without the licensee's knowledge such that a reduction in emergency planning effectiveness occurred. Based on the answers to the Inspection Manual Chapter 0609, Appendix B, "Emergency Preparedness Significance Determination Process," screening questions, the inspectors determined that the issue was of very low safety significance. No violation of regulatory requirements occurred. (Section 1R14.1)

To Be Determined. Units 1 and 2. The inspectors identified a URI concerning a 10 CFR 50.59 process that did not refer emergency planning issues to 10 CFR 50.54(q) for further screening; a lack of instructions, procedures, or drawings to help emergency response facility communication technicians determine the full magnitude of a problem and identify potential solutions; the replacement of Emergency Operations Facility (EOF) and Joint Public Information Center equipment by personnel other than the licensee without licensee knowledge; and the inability to remotely monitor emergency notification system (ENS) telephone system performance since January 17, 2003.

The inspectors determined that the issue was more than minor because: 1) it affected the emergency preparedness cornerstone attributes of facilities and equipment, procedure quality, and response organization performance. The 10 CFR 50.59, instruction, and equipment replacement issues did not represent an immediate safety concern and were considered a URI pending further regulatory review. (Section 1R14.1)

<u>Licensee-Identified Violations</u>

Violations of very low safety significance, which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program (CAP). These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at full power and remained there until January 2, 2003, when power was reduced to 97.5 percent in support of auxiliary feedwater (AFW) pump testing. Unit 1 returned to full power operation on January 3 and remained there until January 13 when power was reduced to 99 percent as a compensatory measure for unexpected #3 turbine governor valve movement. Unit 1 returned to full power on January 14 and remained there until February 3 when, due to the installation of Leading-Edge feedwater flow meter instruments and power uprate activities, reactor power was re-scaled to 98.6 percent. Unit 1 commenced power escalation activities on February 11 and achieved the new rated thermal power of 1540 megawatts thermal later the same day. Unit 1 remained at full power until February 27 when power was reduced to 92 percent in response to pressurizer liquid space and reactor coolant system (RCS) hot leg sample valve primary containment isolation concerns. Unit 1 returned to full power later the same day following insolation of the containment leak path. Unit 1 remained at full power until March 7 when power was reduced to 97.5 percent for P-38A motor-driven auxiliary feedwater (MDAFW) pump testing. Unit 1 returned to full power later the same day and remained there until March 8 when power was reduced to 97.3 percent for P-38B MDAFW pump testing. Unit 1 returned to full power later the same day and remained there until March 9 when power was reduced to 97.5 percent for 1P-29 turbine-driven auxiliary feedwater (TDAFW) pump testing. Unit 1 returned to full power later the same day and remained there until March 22 when power was reduced to 65 percent for main turbine stop valve, atmospheric steam dump, condenser steam dump, and crossover steam dump testing. Unit 1 returned to full power operations on March 23 and remained there until March 27 when power was reduced to 99.6 percent to support chemical and volume control system instrument calibrations. Unit 1 returned to full power later the same day and remained there until March 28 when power was reduced to approximately 98 percent as the result of a plant process computer system malfunction. Unit 1 returned to full power later the same day and remained there for the rest of the inspection period.

Unit 2 began the inspection period at full power and remained there until January 2, 2003, when power was reduced to 97.5 percent in support of AFW pump testing. Unit 2 returned to full power operation on January 3 and remained there until January 18 when power was reduced to 65 percent for main turbine stop valve, atmospheric steam dump, condenser steam dump, crossover steam dump, and AFW pump testing. Unit 2 returned to full power on January 19 and remained there until February 3 when, due to the installation of Leading-Edge feedwater flow meter instruments and power uprate activities, reactor power was re-scaled to 98.6 percent. Unit 2 commenced power escalation activities on February 8 and achieved the new rated thermal power of 1540 megawatts thermal later the same day. Unit 2 remained at full power until March 7 when power was reduced to 97.5 percent for P-38A MDAFW pump testing. Unit 2 returned to full power later the same day and remained there until March 8 when power was reduced to 97.5 percent for P-38B MDAFW pump testing. Unit 2 returned to full power later the same day and remained there until March 10 when power was reduced to 97 percent for 2P-29 TDAFW pump testing. Unit 2 returned to full power on March 11 and remained there for the rest of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Emergency Preparedness

1R04 Equipment Alignment (71111.04)

.1 Façade Freeze Protection Complete System Walkdown

b. Inspection Scope

During the week of February 21, 2003, the inspectors performed a walkdown of the façade freeze protection system and reviewed the procedures associated with freezing to assess the adequacy of the system and procedures following three separate freezing events during the previous week. During the Unit 1 and Unit 2 walkdowns, the inspectors visually inspected lagging, heat tracing, and thermocouples for proper installation. The inspectors also reviewed actions taken in response to the freeze issue that occurred during the previous week to ensure that the actions were thorough and complete. The inspectors compared the actions to those taken in the previous 4 years during which façade freeze issues had also occurred.

b. Findings

No findings of significance were identified.

.2 Main Steam Partial Walkdown

a. Inspection Scope

During the week of February 15, 2003, the inspectors reviewed design bases and walked down the Unit 1 main steam system, moisture separator reheaters, main steam dumps, and the associated steam piping to ensure proper operation of the systems before, during, and following the Unit 1 power uprate. The inspectors also reviewed engineering checklists following the power uprate.

b. Findings

No findings of significance were identified.

.3 Main Feedwater Partial Walkdown

a. Inspection Scope

During the week of February 8, 2003, the inspectors reviewed design bases and walked down the main feedwater, condensate, feedwater heaters, and the associated piping and valves before, during, and following the Unit 2 power uprate. The inspectors also reviewed engineering checklists following the power uprate.

b. Findings

No findings of significance were identified.

.4 Unit 1 TDAFW System Partial Walkdown

a. Inspection Scope

During the week of March 22, 2003, the inspectors walked down the Unit 1 TDAFW pump valve lineup to verify that the system was properly restored to operable status following maintenance to replace the recirculation orifice. The inspectors walked down the pump supply and discharge flow paths and the turbine steam supply to ensure that the system remained capable of performing the intended safety function.

b. Findings

No findings of significance were identified.

.5 Unit 2 TDAFW System Partial Walkdown

c. Inspection Scope

During the week of March 17, 2003, the inspectors performed a partial system walkdown of the Unit 2 TDAFW pump to verify correct system configuration following an auxiliary operator report of slight vibration and noise in the pump discharge piping. The inspectors interviewed system engineering and non-destructive evaluation personnel and used system drawings, operations periodic check procedures, and infrared inspection results to determine whether suspected back-leakage from check valve 2AF-100, "2HX-1A Steam Generator Auxiliary Feedwater First Off Check Valve," affected system configuration and the ability to perform the intended safety function. The inspectors compared surface piping temperatures with saturated steam pressure and temperature conditions to verify that no vapor pockets existed in the AFW injection piping. The inspectors also evaluated other elements, such as material condition, housekeeping, and component labeling. Finally, the inspectors reviewed CAP document CAP031815, "Insulation Missing," which was initiated as a result of this inspection activity and discussed insulation that had been left on top of a covered electrical cable tray following removal from a primary containment service water (SW) penetration.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Walkdown of Selected Fire Zones

a. Inspection Scope

The inspectors walked down the following areas to assess the overall readiness of fire protection equipment and barriers:

- Fire Zones 128, 129, and 130, Holdup Tank Room - T8A, B, and C
- Fire Zone 216, Volume Control Tank Valve Gallery
- Fire Zone 109, Residual Heat Removal (RHR) Pump Room - 2P10B
- Fire Zone 108, RHR Pump Room - 2P10A
- Fire Zone 304, Area A23N, AFW Pump North Room
- Fire Zone 304, Area A23M, AFW Pump Middle Room
- Fire Zone 304, Area A23S, AFW Pump South Room
- Primary Auxiliary Building (PAB) Epoxy Flooring ASTM E 84 Report
- Fire Zone 692, Area A51, Warehouse #3

Emphasis was placed on the control of transient combustibles and ignition sources, the material condition of fire protection equipment, and the material condition and operational status of fire barriers used to prevent fire damage or propagation. Area conditions/configurations were evaluated based on information provided in the licensee's "Fire Hazards Analysis Report," August 2001. The inspectors also walked down the listed areas to verify that fire hoses, sprinklers and portable fire extinguishers were installed at their designated locations, were in satisfactory physical condition, and were unobstructed, and to verify the physical location and condition of fire detection devices. Additionally, passive features such as fire doors, fire dampers, and mechanical and electrical penetration seals were inspected to verify that they were located per Fire Hazards Analysis Report requirements and were in good physical condition.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

.1 Resident Inspector Review of Heat Sink Performance

a. Inspection Scope

During the week of March 22, 2003, the inspectors reviewed documents associated with the testing, inspection, cleaning, and performance trending of heat exchangers, primarily focusing on the spent fuel pool heat exchangers, HX-13A and B, and the PAB battery room coolers, HX-105A and B. The heat exchangers were selected to evaluate the licensee's corrective action for heat exchanger cleaning. The room coolers were chosen because of a degraded condition caused by micro-fouling. The operability determination was reviewed for engineering rigor and completeness. The inspectors reviewed completed surveillance tests and associated calculations, and performed independent calculations to verify that these activities adequately ensured proper heat transfer. The inspectors reviewed the documentation to confirm that the test or inspection methodology was consistent with accepted industry and scientific practices, based on review of heat transfer texts and Electrical Power Research Institute standards (EPRI NP-7552, Heat Exchanger Performance Monitoring Guidelines, December 1991; and EPRI TR-107397, Service Water Heat Exchanger Testing Guidelines, March 1998).

The inspectors reviewed condition reports concerning heat exchanger and ultimate heat sink performance issues to verify that the licensee had an appropriate threshold for identifying issues and entering them in the CAP. The inspectors also evaluated the effectiveness of the corrective actions for identified issues, including the engineering justifications for operability, if applicable.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

During the week of March 22, 2003, the inspectors observed the simulator portion of operator requalification examinations to evaluate the adequacy and proficiency of licensed operator performance. Where failures occurred, the inspectors reviewed licensee actions to remove individuals from control room duties pending remedial training and re-examinations. The inspectors also reviewed the examination, remedial training, and re-examination data for adequacy and accuracy. Finally, the inspectors observed the post-examination critique and evaluated crew involvement in the discussions to assess the rigor of the licensee's self-critique process.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

.1 Routine Resident Inspector Review of Selected Systems

a. Inspection Scope

The inspectors reviewed the implementation of the maintenance rule to verify that component and equipment failures were identified, entered, and scoped within the maintenance rule and that selected systems, structures, and components were properly categorized and classified as (a)(1) or (a)(2) in accordance with 10 CFR 50.65. The inspectors reviewed station logs, maintenance work orders (WOs), condition reports, action requests (ARs), (a)(1) corrective action plans, functional failures, unavailability records, selected surveillance test procedures, and a sample of condition reports to verify that the licensee was identifying issues related to the maintenance rule at an appropriate threshold and that corrective actions were appropriate. The inspectors also walked down portions of the systems to examine material condition, ensure the proper implementation of action plans, and to verify past functional failures had been corrected. Additionally, the inspectors reviewed the licensee's performance criteria to verify that the criteria adequately monitored equipment performance and to verify that licensee changes to performance criteria were reflected in the licensee's probabilistic risk assessment. Specific components and systems reviewed were:

- SW during the week of March 29, 2003
- Component cooling water during the week of March 29, 2003

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of plant risk, scheduling, configuration control, and performance of maintenance associated with planned and emergent work activities to verify that scheduled and emergent work activities were adequately managed. In particular, the inspectors reviewed the program for conducting maintenance risk safety assessments to verify that the planning, risk management tools, and the assessment and management of on-line risk were adequate. The inspectors also reviewed actions to address increased on-line risk when equipment was out-of-service for maintenance, such as establishing compensatory actions, minimizing the duration of the activity, obtaining appropriate management approval, and informing appropriate plant staff, to verify that these actions were accomplished when on-line risk was increased due to maintenance on risk-significant systems, structures, and components. The maintenance risk assessments for work planned for the weeks beginning on the dates listed below were reviewed:

- December 29, 2002. This work included chemical and volume control system calibrations, undervoltage relay testing, component cooling water pump maintenance, and AFW pump testing. In addition, the inspectors reviewed CAP031681, "Activities Missed In On-Line Risk Evaluations," which was written as a result of this inspection activity and discussed volume control tank level transmitter calibrations which were not included in the work week or daily risk profiles, despite being included in the licensee's modeling tools.

- January 5, 2003. This work included charging pump maintenance, safety-related battery charger inspections, and scheduled SW pump maintenance. Also, the inspectors reviewed CAP031681, "Activities Missed In On-Line Risk Evaluations," which was written as a result of this inspection activity and discussed monthly diesel-driven fire pump functional tests during which the licensee had not included TDAFW pump bearing cooling unavailability impacts during periods of diesel engine cooldown.

- February 2, 2003. This work included Unit 2 power uprate activities, safety injection (SI) and charging pump maintenance, safety-related battery cell replacements, and reactor protection and safeguards logic testing. In addition, the inspectors reviewed CAP031709, “Safety Monitor Scheduled Activities For Week W02 Missing 2P2A,” which was written as a result of this inspection activity and discussed scheduled Unit 2 charging pump breaker maintenance activities that were not included in the weekly risk profile projection.

- February 16, 2003. This work included G-05 GT corrective maintenance, reactor trip breaker replacements, auxiliary building battery room cooler cleaning, and SI system pump and valve testing. In addition, the inspectors reviewed two CAP documents which were written as a result of this inspection activity. The first was CAP031233, “NP [Nuclear Procedure] 10.3.7 Not Followed, Safety Monitor Unavailability Project Inaccurate,” which discussed reactor trip breaker maintenance that was not included in the shift technical advisor’s daily review and projection of risk, despite having been a scheduled activity. The second was CAP031202, “Safety Monitor ‘Planned’ Scheduled Activities On The Risk Profile Incorrect,” which discussed an unavailable condenser steam dump valve that had been assigned to the wrong Unit’s risk profile, an error unnoticed by the work planning, risk management and operations staff for over 4 days.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-Routine Plant Evolutions (71111.14)

.1 ENS Power Failure

c. Inspection Scope

During the week of January 27 and February 2, 2003, the inspectors reviewed a partial loss of communications systems in the Emergency Response Facilities (ERFs) to verify that appropriate licensee actions had been taken and that facility changes had not reduced the effectiveness of the Emergency Plan. The inspectors reviewed the corrective actions that were written and the work package for equipment modifications in the EOF.

b. Findings

The inspectors identified one finding of very low risk significance for not having adequate configuration control and not providing sufficient drawings and instructions to maintenance and operations personnel during an emergency notification telephone system battery charger failure and subsequent replacement activities. In addition, the inspectors identified a URI concerning a 10 CFR 50.59 process that did not refer emergency planning issues to 10 CFR 50.54(q) for further screening; a lack of instructions, procedures, or drawings to help ERF communication technicians determine the full magnitude of a problem and identify potential solutions; the replacement of EOF and Joint Public Information Center equipment by personnel other than the licensee without licensee knowledge; and the inability to remotely monitor ENS telephone system performance since January 17, 2003.

Description

Problems with the ENS telephone system began on December 28, 2002, and concluded with a battery charger replacement on January 17, 2003. On December 28, the operations department was notified by security personnel that there had been a loss of power at the Site Boundary Control Center (SBCC), which includes the EOF, due to a vehicular accident involving the SBCC electrical power lines. The licensee contacted Wisconsin Electric Energy Services in Milwaukee who then contacted Wisconsin Electric Telecon and SBC Ameritech. A technician was subsequently dispatched from Appleton to troubleshoot and repair the equipment.

On the afternoon of December 28, an Ameritech technician restored one of the ENS battery chargers in the SBCC. The repair, however, was not effective because the battery charger tripped a second time due to overcurrent after the technician left the building. Because there was no alarm at the plant and the alarm station in Milwaukee was not manned during the holiday period, the second trip was not detected. On December 31, the operations department was notified by security personnel that there was a loss of telephone capability at the SBCC. The ENS telephone system batteries had discharged because of the loss of power to the 6000-series PBX phones causing a loss of the EOF ringdown lines to other ERFs; the Federal Telephone System telephones in the Control Room, the Technical Support Center, and the EOF; and the two-digit dial phones at the EOF and other facilities. Ameritech technicians again attempted to restore the power on the evening of December 31. The battery charger again tripped on overcurrent and was unable to be reset. The technicians then connected a larger charger and charged the ENS telephone system battery until one of the chargers would reset and maintain power. Wisconsin Electric Telecon staff also developed a plan to change the battery charger with a newer model.

During the week of January 6, 2003, at a morning planning meeting, one of the plant staff asked if the battery charger change had been reviewed using the 10 CFR 50.59 and/or the 50.54(q) process. An engineer responded that there had not been a 50.59 or 50.54(q) screening or evaluation since all of the work was being done by an off-site group. During the meeting, licensee management made the decision to stop the battery charger replacement activities until a 50.59 screening had been completed. During subsequent reviews, the inspectors identified that:

- The 50.59 evaluation had identified that pertinent ENS telephone system information was described in the Emergency Plan Manual, Procedure EP 7.0, “Emergency Facilities and Equipment.” The licensee’s 50.59 process, however, had not referred to 50.54(q) for further screening and in the case of the ENS telephone system battery charger replacement, a 50.54(q) evaluation had not been completed.

- During the battery charger replacement, the licensee noted that no instructions, procedures, or drawings were available to help the technicians understand the magnitude of the problem or to identify potential solutions to the loss of power.

- During walkdowns with the inspectors after the charger replacement, the licensee stated that the ENS telephone system batteries had been changed sometime during the latter part of 2002. Licensee personnel stated that they had not been informed of the battery replacement activities until the charger had been replaced in January 2003.

- Following the charger replacement on January 17, 2003, the monitoring system connected to Milwaukee had been not reconnected. Wisconsin Electric Telecon staff stated that the monitoring system would be connected sometime in the future.

- When asked about configuration control of the EOF and Joint Public Information Center, the inspectors were informed that parts of the facilities were maintained by someone other than the licensee and that changes may have been made without informing the licensee.

<u>Analysis</u>

The inspectors determined that not having adequate configuration control and not providing sufficient drawings and instructions to maintenance and operations personnel during the ENS telephone system battery charger failure and subsequent replacement activities was a performance deficiency. The inspectors determined that this issue warranted a significance evaluation in accordance with Inspection Manual Chapter 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Disposition Screening,” issued on February 21, 2003. The inspectors determined that the issue was more than minor because: 1) it affected the emergency preparedness cornerstone equipment and communications system attribute, and 2) if left uncorrected, would become a more significant safety concern if ERF communication system modifications were made without the licensee’s knowledge such that a reduction in emergency planning effectiveness occurred.

The inspectors determined that a licensee 50.59 process that did not refer emergency planning issues to a licensee 10 CFR 50.54(q) process for further screening; a lack of instructions, procedures, or drawings to help ERF communication technicians determine the full magnitude of a problem and identify potential solutions; the replacement of EOF and Joint Public Information Center equipment by personnel other than the licensee without licensee knowledge; and the inability to remotely monitor ENS telephone system performance since January 17, 2003, constituted a performance deficiency warranting a significance evaluation in accordance with Inspection Manual Chapter 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Disposition Screening,” issued on February 21, 2003. The inspectors determined that the issue was more than minor because it affected the emergency preparedness cornerstone attributes of facilities and equipment, procedure quality, and response organization performance.

<u>Enforcement</u>

Using Inspection Manual Chapter 0609, Appendix B, “Emergency Preparedness Significance Determination Process,” the inspectors used the “Failure to Comply” path with respect to planning standard 10 CFR Part 50.47(b)(8). Based on the answers to the screening questions, the inspectors concluded that the issue of not having adequate configuration control and not providing sufficient drawings and instructions to maintenance and operations personnel during the battery charger failure and subsequent replacement activities was a finding of very low safety significance (Green) (FIN 50-266/301/03-02-01). The inspectors determined that no violation of regulatory requirements had occurred because normal land-based telephone systems had remained available, thereby maintaining, with compensatory measures, emergency communications capabilities.

The safety significance of the licensee 50.59 process that did not refer emergency planning issues to 10 CFR 50.54(q) for further screening; a lack of instructions, procedures, or drawings to help ERF communication technicians determine the full magnitude of a problem and identify potential solutions; the replacement of EOF and Joint Public Information Center equipment by personnel other than the licensee without licensee knowledge; and the inability to remotely monitor ENS telephone system performance since January 17, 2003, were considered a URI pending further regulatory review (URI 50-266/301/03-02-02). None of the 50.59, instruction, or equipment replacement issues represented an immediate safety concern.

.2 Unit 2 Power Uprate

a. Inspection Scope

During the week of February 8, 2003, the inspectors observed the Unit 2 power uprate to ensure procedural compliance and plant systems monitoring during the evolution. The inspectors observed an instrument and control surveillance, crew and engineering briefings, performed system walkdowns, and reviewed the overall work plan.

b. Findings

No findings of significance were identified.

.3 Unit 1 Power Uprate

a. Inspection Scope

During the week of February 12, 2003, the inspectors observed the Unit 1 power uprate to ensure procedural compliance and plant systems monitoring during the evolution. The inspectors observed an instrument and control surveillance, crew and engineering briefings, performed system walkdowns, and reviewed the overall work plan.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Submerged 13.8-kilovolt (kV), 4160-Volt (V), and 480-V Electrical Cables

a. Inspection Scope

During the week of March 10, 2003, the inspectors examined the effects of prolonged submergence on 13.8-kV, 4160-V, and 480-V alternating current electrical cables to determine the potential operability and transient initiation impacts. Specifically, the inspectors focused on the 4160-V alternating current power supply cables from the 1X-04 transformer to the Unit 1 ‘A’ and ‘B’ train safeguards buses; the 480-V alternating current power supply cables to the P-32A and P-32D safety-related SW pumps; and the 13.8-kV power supply cables to the Unit 2, 2X-04 transformer, the transformer supplying offsite power to the Unit 2, 4160-V safeguards buses. The inspectors reviewed vendor correspondence, selected CAP documents, original purchase order specifications, and material history information to attempt to determine the service life of the selected cables during periods of prolonged submergence. The inspectors also interviewed selected system and electrical engineering personnel to determine the licensee’s understanding of the potential impacts of submerged cables and aggressiveness towards addressing the potential issues. Finally, the inspectors reviewed operability determination OPR000048, “480 volt & 4160 volt Cable Issues,” which was written based on the inspectors’ questions concerning vendor correspondence that reflected the opinion that the life of the 4160-V cables could be as short as 30 years.

b. Findings

The inspectors identified a URI concerning the affects of prolonged water submergence on 13.8-kV, 4160-V, and 480-V electrical cables. The actual physical condition, deterioration rates, remaining service life, cable insulation trend predictions, effects of repeated freezing and thawing cycles, potential electrical breaker coordination impacts, cable splice location, potential for collapsed underground conduits, and worse case failure analyses were identified as areas requiring further NRC review.

On March 8, 2003, at the request of the inspectors, engineering personnel briefed the resident inspectors on the status of submerged cable issues at Point Beach, an issue which had been a finding of very low risk significance in NRC integrated Inspection Report 50-266/02-13; 50-301/02-13, Section 4OA2.1. Of at least eight manholes known to have experienced previous flooding at Point Beach, five were selected for initial investigation based on the potential safety impact. The five manholes selected by the inspectors for further review included:

- Manhole No. 3. This manhole contained 4160-V cables connecting the low-side of transformer 1X-04 to cable trays located in the northwest corner of the Unit 1 facade. The 4160-V cables were installed in 1971 during initial construction. Cables located at the bottom of manhole No. 3 had likely been submerged for several years based on corrective action document histories and the installation of flexible sealant material intended to prevent water leakage into Unit 1 facade during the early to mid-1990s. The two lowest tiers of manhole No. 3 contained power supply cables that provided offsite power to the Unit 1, 4160-V safeguards buses, 1A05 and 1A06.

- Manholes No. 1 and 2. Manhole No. 1 contained 480-V power supply cables to safety-related SW pump P-32A. Manhole No. 2 contained 480-V power supply cables to safety-related SW pump P-32D. Both cables were installed in 1971 during initial construction and were known to contain ethylene-propylene-rubber insulation.

- Manholes No. 6 and 18 which contained 13.8-kV cables providing power to the high-side of transformer 2X-04, the transformer providing offsite power to the Unit 2 safeguards buses, 2A05 and 2A06. The 13.8-kV cables were replaced in 1988.

During meetings with engineering personnel on March 12 and 14, the inspectors were informed that correspondence with the 1X-04, 4160-V cable vendor on February 28, 2003, had reflected the vendor's opinion that life on the cables could be as short as 30 years. The vendor provided that the expected life of the cable was 30 years and that the cable, when submerged in water, may or may not fail electrically. During further correspondence on March 14, the vendor indicated that due to low amperage loading, the 4160-V cables were not likely to have degraded significantly due to thermal aging. No information was provided relative to adverse operating conditions such as periods of prolonged submergence. The inspectors also reviewed the initial architect/engineer purchase order specification for the 13.8-kV and 4160-V cables that had been installed in 1971. The specified service condition for the cables required suitability for installation in cable trays, conduit or underground duct banks, in wet and dry locations, and indoors or outdoors. The inspectors noted that the initial purchase specifications contained no requirements for the cables to be qualified for prolonged or continuous periods of submergence.

During a March 14 meeting, the inspectors asked the licensee for the operability basis for the submerged cables. The licensee responded that prompt operability was based on the absence of safeguards bus grounding indications and the low amperage loading of the cables resulting in minimal insulation thermal aging effects. The licensee subsequently completed operability determination OPR000048 on March 17 which concluded that the cables remained operable but non-conforming and that no compensatory actions were required. The operability determination also documented eight corrective action reports since 1996 that discussed differing aspects of the submerged cable issue including steady streams of water into facade cable trays, ice formations in the vicinity of cable trays, inability to pump selected manholes, Operations department noted increases in the amount of ground water leaking into the northern side of the plant, submergence of cables in manholes No. 1 and 2 by at least 6 feet of water on one occasion and to within 18 inches of the manhole cover on another occasion, and the tracking of generic cable aging issues. The licensee's basis for current cabling operability included:

- The 4160-V cable vendor's 30-year expected life being based on fully loaded cables. Since the 1X-04, 4160-V cables were estimated to be loaded at

25 percent of the full load ampacity rating, the licensee maintained that the electrical and thermal degradation of the cables would be significantly less than that expected for 30 years of continuous operation at rated loads.

- The 480-V SW pump cables being loaded at approximately 56 percent of their rated ampacity. Although there was no known vendor life expectancy for these cables, the licensee maintained that since the cables were operating below their voltage, ampacity and temperature ratings, industry experience suggested cable longevity beyond 30 years.

- No recurrent ground fault alarms on the 4160-V or 480-V buses. Also, original cable purchase order specifications were for lengths of cable that provided for continuous runs between terminal points, an indication that splices were unlikely to have been needed. In addition, December 2002 (P-32D) and January 2003 (P-32A) safety-related SW pump motor current evaluation data did not indicate low cable resistances to ground.

- Visual inspections of accessible portions of 4160-V and 480-V cables by engineering personnel on March 15 and asset owner electricians on March 17 revealed no indications of cables splices or jacket deterioration.

Not withstanding the licensee's operability determination, the inspectors considered that many cabling fundamentals remained unknown. First, no trending information relative to cable insulation resistance was available. Hence, the ability to accurately predict cable deterioration rates or remaining service life remained indeterminate. Second, worse case failure analyses remained incomplete. For instance, as of March 21, the licensee had not performed a worst case analysis of the potential damage caused by a 4160-V cable failure at the exit point of the manhole No. 3 underground conduit to the Unit 1 facade. Specifically, the licensee had not determined the other power supplies, control functions, or post-accident monitoring indications that might be lost during such a failure. In response to inspector questioning, the licensee maintained that differential and ground fault relays as well as bolted fault short circuit analyses would minimize any physical damage. Third, final determination of the presence of submerged cable splices throughout the Point Beach site remained an open question at the end of this inspection period. Finally, the inspectors questioned the continuity of offsite power to the Unit 1 and Unit 2 safeguards buses relative to 40-year design and licensing basis requirements. In the case of Unit 1, the vendor expected life of the 1X04, 4160-V cable was 30 years. Licensee records indicated that the actual 4160-V cables were installed in January 1971 reflecting a current service period of at least 32 years.

Analysis

The inspectors determined that not sufficiently managing and monitoring electrical cable degradation during prolonged periods of submergence was a performance deficiency warranting a significance evaluation in accordance with Inspection Manual Chapter 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on February 21, 2003. The inspectors determined that the issue was more than minor because: 1) it affected the cornerstone objective of limiting the likelihood of those events that upset plant stability during shutdown as well as power operations; and 2) if left uncorrected, would become a more significant safety concern in subsequent years if cable degradation were to interrupt the continuity of offsite power to the safeguards electrical buses.

Enforcement

Since the analysis of several cabling fundamentals including deterioration rates, remaining service life, worse case failure analyses, splice locations, and the assurance of continuity of offsite power to safeguards buses remained incomplete at the end of this inspection period, the safety significance of the issue is To Be Determined. The issue did not represent an immediate safety concern and will be considered an Unresolved Item pending completion of further regulatory review (URI 50-266/301/03-02-03). This issue was included in the licensee's CAP as CAP031655, "4160V Cables Possibly Beyond End Of Life."

.2 Main Steam Safety Valve (MSSV) Setpoint Tolerance Was Not Included in the MDAFW Pump Inservice Test Acceptance Criteria

a. Inspection Scope

During and following the week of February 8, 2003, the inspectors reviewed operability determination OPR000044, "MSSV Setpoint Tolerance Not Included in AFW IST [Inservice Test] Acceptance Criteria Calculations," Revisions 0 and 1, to determine the impact of MSSV lift setpoint variances on the ability of the MDAFW pumps to provide design basis flows to the steam generators during postulated accident conditions. The inspectors also reviewed design and licensing basis requirements, Improved Technical Specification (ITS) licensing correspondence, selected engineering calculations, and the most recently completed MDAFW pump quarterly IST results to evaluate the ability of the pump to perform the intended safety function.

b. Findings

No findings of significance were identified.

.3 Condensate Storage Tank (CST) Tank Level Transmitter Cable Separation

a. Inspection Scope

The inspectors reviewed an operability determination OPR0000039, "CST Level Transmitter Cable Separation Issue," concerning the control room level instruments for both CSTs to assess the adequacy of the review for cable separation as required by Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," and Institute of Electrical and Electronic Engineers IEEE-384, "IEEE Standard Criteria for Independence of Class 1E Equipment and Circuits." The inspectors walked down the sections of cable and conduit that were referred to in the operability determination and reviewed the associated corrective actions for CAP030790, "Raceway Separation Requirements for CST Level Indication," and CAP030861, "The Basis for Calling CST Level Indications Operable Needs Revisited." The inspectors reviewed the letters of commitment from Wisconsin Electric dated September 1, 1983, to determine the licensee's implementation of Regulatory Guide 1.97.

b. Findings

No findings of significance were identified.

.4 Unit 1 'D' Electro-Hydraulic Control System Accumulator Seal Failure

a. Inspection Scope

During the week of January 15, 2003, the inspectors reviewed the impact of a failed system accumulator seal ring on system operability. The inspectors interviewed system engineers, observed foreign material retrieval evolutions, examined system chemistry data for trends, reviewed licensee seal ring supply chain controls, evaluated system filter differential pressures, and reviewed main turbine governor valve quarterly testing results to ensure that the failed seal ring material had not affected electro-hydraulic system operations.

b. Findings

No findings of significance were identified.

.5 Gas Turbine (GT) Generator Monthly Run

a. Inspection Scope

During the week of January 15, 2003, the licensee aborted the G-05 monthly load run due to fuel oil leaks on the suction piping. The inspectors walked the GT generator down with a system engineer to determine if the machine could have met its 72-hour mission time. During the system walkdowns, the inspectors observed the areas of concern, including the flange fuel oil leaks; a horizontally mounted, leaking relief valve; and a weld leak at a T-junction on the suction piping.

The inspectors also reviewed documentation on availability and reliability for G-05, the Point Beach station blackout power source. The inspectors reviewed issues concerning G-05 not having been able to meet the FSAR reliability requirements. The inspectors contacted Nuclear Reactor Regulation (NRR) office to discuss the >95 percent reliability commitment and the effects on the station blackout rule, 10 CFR 50.63.

The inspectors discussed with engineering personnel the reliability of the GT generator and the numbers that are used to determine the reliability. This included the Regulatory Guide 1.155, "Station Blackout," and Nuclear Management and Resources Council (NUMARC) 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," requirements and the number of start and load failures that decreased reliability below 95 percent.

b. Findings

No findings of significance were identified.

.6 Frequent Digital Metal Impact Monitoring System (DMIMS) Alarms On Unit 1 ‘A’ Steam Generator Primary Channel

a. Inspection Scope

During the week of February 8, 2003, the inspectors reviewed the receipt of 17 DMIMS alarms on the Unit 1, ‘A’ steam generator primary channel, VBM-754, to evaluate the potential for RCS loose parts. The inspectors interviewed engineering and operations personnel to understand the characteristics of an actual metal impact as compared to those caused by internal hardware problems. The inspectors reviewed the adequacy of the alarm response procedures, listened to the VBM-754 channel in the control room, reviewed Condition Evaluation CE01114, and reviewed future work plans to determine if the licensee had taken appropriate actions.

b. Findings

No findings of significance were identified.

.7 G-02 EDG Direct Current (DC) Fuel Oil Pump Common Cause Failure Evaluation

a. Inspection Scope

During the week of March 8, 2003, the inspectors reviewed evaluations associated with the failure of the G-02 (Unit 2, ‘A’ Train) EDG DC fuel oil pump to stop following completion of monthly surveillance testing activities on January 12, 2003, to determine potential impacts on other emergency sources of electrical power. The inspectors interviewed system engineers, reviewed CAP documents and evaluations, analyzed electrical schematics, and verified electrical interlock interactions to ensure the adequacy of the licensee’s conclusions.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (OWAs) (71111.16)

.1 Cumulative Effect of OWAs

a. Inspection Scope

Using the OWA list effective during the week of March 19, 2003, the inspectors evaluated the cumulative effect of these workarounds on plant operations. The inspectors evaluated outstanding OWAs to determine the overall complexity and aggregate effects on operator performance. The inspectors reviewed the interactions between OWAs associated with the crossover steam dump system, steam dump valves to the condensers, a steam generator atmospheric steam dump valves, safety-related battery room ventilation fans, direct current under/over voltage alarms received during the start of safeguards equipment, Unit 2 main turbine electro-hydraulic control system, EDG fuel oil receipt tank level indication, circulating water system, and low flow concerns associated with the AFW pumps to evaluate the operator's ability to respond to postulated events and still implement abnormal and emergency operating procedures. The inspectors also reviewed OWA meeting minutes to verify that the licensee had been conducting periodic reviews of OWAs and considering the total impact of workarounds on plant operations.

b. Findings

No findings of significance were identified.

.2 Fuel Oil Receiving Tank Level Indicator

a. Inspection Scope

During the week of March 24, 2003, the inspectors reviewed OWA 0-02R-004 FO to verify that the workaround was properly classified and dispositioned in accordance with the criteria of the licensee’s procedure. The workaround concerned the inability to calibrate the level indicator associated with T-173, a tank used to receive fuel oil for the EDGs. The inspectors reviewed the adequacy of licensee actions to address the issue; examined the receiving tank and level indicator to verify that all impacts were limited to the local area; verified the adequacy of posted caution tags; reviewed selected drawings; and evaluated the potential risk impacts to ensure that the workaround did not impact the operators’ ability to implement abnormal or emergency operating procedures.

b. Findings

No findings of significance were identified.

.3 Review of Total Operator Burden Summaries

a. Inspection Scope

During the week of March 24, 2003, the inspectors reviewed licensee operator burden summary records to determine if any control room deficiencies, lit annunciators, or installed temporary modifications represented a potential operator workaround. The inspectors also reviewed degraded instrument, workaround, temporary modification, control room WO, and lit annunciator trend histories to evaluate licensee effectiveness at minimizing and removing operator burdens. Finally, the inspectors conducted control boards walkdowns to compare existing WO stickers with the licensee’s list of control board deficiencies to verify that all deficiencies were being effectively tracked and evaluated for cumulative impacts.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

During the week of February 10, 2003, the inspectors reviewed the design change package and the work associated with a GT generator fuel oil relief valve replacement to verify the accuracy of the design change and that the work was completed in accordance with the work package. The inspectors reviewed the 50.59 screening to determine if all current licensing basis and justifications were accurate. The inspectors walked down the system and noted the changes caused by the replacement of obsolete equipment and discussed effects of the new equipment on the operability of the system with the design engineers.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (PMT) (71111.19)

.1 EDG Safety-Related Protective Relay Calibration Procedure Inadequacies

a. Inspection Scope

During and following the week of January 13, 2003, the inspectors reviewed PMT activities for the G-03 (Unit 1, ‘B’ Train) EDG following a 2-year maintenance overhaul. The inspectors reviewed the PMT to ensure that it was appropriate for the scope of work performed and the diesel remained capable of performing the intended safety function. The inspectors observed portions of the maintenance to examine the material condition of selected engine components. The inspectors also observed portions of the PMT activities to verify that EDG fast-start capabilities were within TS time limits. The inspectors reviewed the completed test and WO documentation to determine the adequacy of the procedures used; to verify that the test data were complete, appropriately verified, and met the requirements of the test procedure; and to ensure the system had been restored to an operable status. Additionally, the inspectors reviewed CAP document 028052, “Discrepancies Within Data Sheets for RMP [Routine Maintenance Procedure] 9043-32, G-03 Protective Relay Cals,” which was written as a result of this inspection activity and discussed six quantitative acceptance criteria discrepancies associated with the maintenance procedure. Finally, the inspectors reviewed the most recently completed protective relay calibration records associated with three other EDGs to determine the extent of the deficiencies associated with EDG safety-related protective relay calibration procedures.

b. Findings

The inspectors identified a finding of very low safety significance (Green) concerning inadequate EDG safety-related protective relay calibration procedures which contained quantitative acceptance criteria limits that did not correspond to vendor recommended values. Despite multiple opportunities for procedure writers, technical reviewers, relay technicians, maintenance work planners, electrical maintenance first-line supervisors, and operations personnel to have identified these errors, each of the four procedures used to calibrate the EDG safety-related protective relays were found to contain similar quantitative acceptance criteria errors. A Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was identified.

Description

While reviewing RMP 9043-32, “Emergency Diesel Generator G-03 Safety Related Protective Relay Calibration,” Revision 4, the inspectors identified several discrepancies associated with vendor recommended relay tolerances and the upper and lower acceptance limits found in the data sheets. In two cases, the vendor recommended relay tolerances were not correctly translated into upper and lower acceptance criteria values. The inspectors identified that:

- On Data Sheet 5, “C-81 G-03 Overload Relay,” the vendor recommended device 67P1, 67P2, and 32 tolerance limits as ±2 percent of the nominal value. The lower and upper data table acceptance thresholds for devices 67P1, 67P2, and 32, however, were based on values associated with a ±5 percent tolerance.

- On Data Sheet 11, “1X06/1B40 Breaker 1A52-81 Device 50G,” the vendor recommended the device 50G/Type GKT amperage tolerance as ±20 percent of the nominal value of 10 amps. The lower data table acceptance threshold for the device, however, was based on a minus 10 percent tolerance limit instead of the recommended 20 percent.

In addition, the inspectors identified four other discrepancies associated with RMP 9043-32 data sheets. On Data Sheets 1 (G-03 Output Breaker 1A52-80, Time Delay Overcurrent), 2 (G-03 Output Breaker 2A52-87), and 9 (1X06/1B40 Breaker 1A52-81 Device 51), acceptance thresholds associated with ‘trending-purposes-only’ relay settings were found to be outside of vendor recommended tolerances. While not out-of-specification for operability purposes, no discussion of the cumulative or potential impact of leaving these relays inservice without adjustment was performed by the licensee. Finally, the trending values associated with Data Sheet 6 (C-81 G-03 Differential Relay, Device 87, Type SA-1) applied a ±10 percent tolerance for the upper and lower acceptance thresholds whereas the vendor recommended tolerance was ±5 percent. Since the 10 percent criteria was incorrectly applied to the trending-only acceptance thresholds, the licensee failed to notice that the as-found and as-left values were outside of the intended ±5 percent tolerance.

The inspectors also obtained and reviewed the most recently completed copies of RMPs 9043-12, 9043-22, and 9043-42 to determine the extent-of-condition of the data sheet errors relative to the G-01 (Unit 1, ‘A’ Train), G-02 (Unit 2, ‘A’ Train), and G-04 (Unit 2, ‘B’ Train) EDGs. Upon further review, the inspectors identified that:

- For RMP 9043-12 associated with the G-01 EDG, Data Sheet 5 (Calibration of Type CW, Overload/Reverse Power Relays) the vendor recommended amperage tolerance for Device 67P-1 and 67P-3 was +3 or -0 percent. However, the tolerance applied to the specific line item in the data table read “PU 396 W @ Tap of 400 W, plus 0 percent or minus 3 percent.” This represented an internal contradiction in same data table that was neither questioned or resolved by the licensee.

Also, the plus 3 percent tolerance when applied to the device 67P-1 and 67P-3 "PU 396 W" reading provided an upper acceptance criteria of 408 W (396 x 1.03 = 408). In Steps 5.11 and 5.12, the relay technicians recorded the as-found and as-left values for devices 67P-1 and 67P-3 as 408 W, a value found and left at the upper acceptable limit with no licensee question, comment, or action.

Finally, for device 67RP the vendor recommended tolerance for the "PU 40 W @ Tap of 40W" reading was ±3 percent. The lower acceptance threshold for this reading, however, was based on -1 percent instead of the vendor recommended 3 percent.

- For RMP 9043-22 associated with the G-02 EDG, Data Sheet 5 (Calibration of Type CW, Overload/Reverse Power Relays) contained an error similar to that in RMP 9043-12, Data Sheet 5 for device 67RP in that the tolerance applied to the lower acceptance limit for "PU 40 W @ Tap of 40W" value was 1 percent instead of the vendor recommended 3 percent.

  The inspectors also noted that Temporary Procedure Change 2002-0074, "Emergency Diesel Generator G-02 Safety Related Protective Relay Calibration," had been performed on February 16, 2002, to correct the same device 67P-1 and 67P-3 errors discussed for RMP 9043-12, Data Sheet 5. The inspectors noted that while the licensee had corrected the problem for G-02 by using a temporary procedure change, a similar error with the G-01 EDG went undetected and uncorrected.

- For RMP 9043-42 associated with the G-04 EDG, Data Sheet 5, "Diesel Generator Control Panel C-82," device 67P1, 67P2, and 32 tolerance limits were given as ±2 percent of the nominal value. The lower and upper acceptance thresholds for devices 67P1, 67P2, and 32, however, were based on values associated with a ±5 percent tolerance.

  In addition, the licensee performed Temporary Procedure Change 2002-0452, "Emergency Diesel Generator G-04 Safety Related Protective Relay Calibration," for Data Sheet 6 (Diesel Generator Control Panel C-82, Device 87, Type SA-1) on July 19, 2002, which deleted 3 trend-only data points. In reviewing the temporary procedure change, maintenance and operations personnel failed to notice that a ±10 percent tolerance had been applied to the upper and lower acceptance thresholds whereas the vendor recommended tolerance had been ±5 percent. The temporary changes made to RMP 9043-42 represented an opportunity to have identified and corrected the same errors associated with RMP 9043-32, Data Sheet 6, an opportunity that was neither realized or taken by the licensee.

Analysis

Incorrectly translating vendor recommended tolerances into upper and lower acceptance criteria resulted in a potential situation where as-found relay settings could have been recorded in the data tables, appeared acceptable based on the provided acceptance criteria, and yet have been out of tolerance relative to vendor recommendations. This could have potentially impacted EDG operability and electrical breaker coordination during electrical fault conditions. Between the four protective relay calibration RMPs and two temporary procedure changes, the inspectors estimated that not less than 32 licensee personnel in diverse parts of the organization had an opportunity to identify the data sheet errors. Inability to have self-identified and corrected these errors represented an example of a lack of attention-to-detail and questioning attitude associated with the procedure revision, technical review, relay technician, maintenance work planning, electrical maintenance first-line supervisor, and operations portions of the licensee organization.

The inspectors determined that safety-related EDG relay calibration procedures which contained quantitative acceptance criteria limits that did not correspond to the vendor recommended tolerances was a performance deficiency warranting a significance evaluation in accordance with Inspection Manual Chapter 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on February 21, 2003. The inspectors determined that the issue was more than minor because: 1) it affected the mitigating systems cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events, and 2) if left uncorrected, would become a more significant safety concern in subsequent years if out-of-specification EDG safety-related protective relay settings affecting equipment operability and electrical distribution system coordination were left in service and not corrected.

The inspectors used Manual Chapter 0609, Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," regarding mitigating systems and determined that the finding was not a design or qualification deficiency, did not represent an actual loss of the safety function, or involve internal or external initiating events. Therefore, the finding screened as Green, a finding of very low safety significance.

Enforcement

Appendix B, Criterion V, of 10 CFR Part 50, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and include quantitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to the above, routine maintenance procedures RMP 9043-12, "Emergency Diesel Generator G-01 Safety Related Protective Relay Calibration," Revision 4, Data Sheet 5; RMP 9043-22, "Emergency Diesel Generator G-02 Safety Related Protective Relay Calibration," Revision 3, Data Sheet 5; RMP 9043-32, "Emergency Diesel Generator G-03 Safety Related Protective Relay Calibration," Revision 4, Data Sheets 5 and 11; and RMP 9043-42, "Emergency Diesel Generator G-04 Safety Related Protective Relay Calibration," Revision 3, Data

Sheet 5 contained quantitative acceptance criteria that were not in accordance with vendor recommendations.

Since, all as-left, safety-related protective relay settings were either at or within the vendor recommended tolerances and all EDG post-maintenance operability tests had been performed satisfactorily, the inspectors determined that the operability of the EDGs had not been adversely impacted and the EDGs, if called upon, would have been able to perform the intended safety function. Accordingly, this violation is being treated as a Non-Cited Violation (NCV 50-266/301/03-02-04) consistent with Section VI.A. of the NRC Enforcement Policy. This violation was entered into the licensee's corrective action system as CAP031140, "Discrepancies Within Data Sheets for RMP 9043-32, G-03 Protective Relay Cals."

.2 G-05 GT Generator Return-to-Service Prior to Completion of Troubleshooting and Maintenance Activities

a. Inspection Scope

During the week of March 8, 2003, the inspectors reviewed PMT of the G-05 GT to ensure that return-to-service activities were properly coordinated and correctly documented. The inspectors reviewed the troubleshooting plan and inspection results from the week of testing.

b. Findings

Introduction

One finding of very low risk significance (Green) was identified. The finding was related to the return-to-service of the G-05 GT prior to completion of troubleshooting efforts involving starting diesel oil samples and certain maintenance activities.

Description

The G-05 GT was run on February 12, 2003, for 2½ hours. At the completion of the run, an engine oil sample was drawn per procedure from G-500, the G-05 starting diesel engine. The sample indicated excessive amounts of coolant and the GT was declared inoperable. Because the GT was relied upon to meet 10 CFR Part 50 Appendix R requirements, fire watches were established. Engineering and maintenance personnel began a troubleshooting plan that included pressurizing the coolant system during cold and hot conditions. Inspections were made without disassembly of the diesel and no indications of leak paths were found. On February 13, maintenance personnel began using RMP-9201, "Control and Documentation for Troubleshooting and Repair Activities," to identify the location of the G-500 coolant leak into the lubricating oil system.

On February 19, the GT was started and run for 2 hours and 20 minutes. Before, during, and after the run the coolant and oil levels were checked with no indications of leakage identified. The GT was declared available for maintenance rule and risk purposes, but remained out-of-service pending the evaluation of the diesel coolant intrusion into the oil.

Operations personnel began periodic monitoring of oil and coolant levels. On February 24, G-500 was run and the oil and coolant levels were verified within acceptable ranges.

On March 1, the GT was successfully tested in accordance with PC-29, "Monthly Gas Turbine and Auxiliary Diesel Load Test." Operations personnel subsequently declared the GT operable and discontinued 10 CFR Part 50 Appendix R compensatory fire watches. On March 3, the analysis of the oil sample from the February 12 run was received by system engineering. The oil sample analysis indicated advanced oil degradation; elevated levels of lead, tin, molybdenum, and aluminum; and the onset of engine bearing damage. As a result of the analysis, the GT was again declared inoperable. On March 4, results from an oil sample analysis from the February 19 run was received and confirmed the results of the February 12 sample analysis.

Analysis

The inspectors interviewed system engineering and maintenance personnel after the GT was declared operable on March 1, 2003. The inspectors also reviewed the troubleshooting documentation and determined that it was incomplete. The GT system engineers and the maintenance personnel performing the troubleshooting were not aware that operations personnel intended to perform PC-29 to return the GT to service. During the interviews performed after March 1, the inspectors determined that the system engineers had been waiting for the oil sample analysis results to determine the extent of damage that the engine had incurred and that maintenance still had the troubleshooting work package open. Engineering and operations management had discussed returning the GT to service and made the decision to perform PC-29 on March 1. This information was relayed to the Duty Shift Supervisor, but not to the maintenance and systems engineers associated with the troubleshooting. This lack of coordination and communication caused the GT to be inappropriately returned to service on March 3.

The inspectors' review of RMP-9201 revealed that operations personnel had not approved the troubleshooting plan and that there were no post-maintenance tests defined in the plan to return the GT to service. During discussions with plant management, the inspectors determined that verbal plans had been made about how to return the GT to service, but these plans were not formalized nor communicated across all of the departments that were involved in the process. The inspectors identified a performance deficiency in that the GT was returned to service and Appendix R fire watches were secured, without completion of the troubleshooting plan or an operability determination having been completed. Contributing to this performance deficiency was a lack of interdepartmental communications and coordination.

The inspectors determined that returning the G-05 GT to service without completion of the troubleshooting plan was of more than minor significance since the issue affected the availability, reliability, and capability of the G-05 GT, a mitigating system. The inspectors used Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," regarding mitigating systems and determined that the finding was not a design or qualification deficiency; did not represent an actual loss of the safety function for any mitigating system and did not result in a loss of function of a single train of any mitigating systems for greater than its TS-allowed outage time; did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours; did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating events; and did not involve the loss of a safety function that contributed to external event initiated core damage accident sequences. Therefore, the finding screened as Green and was of very low safety significance.

Enforcement

Returning equipment to service without having a clear understanding or a complete and comprehensive assessment of outstanding troubleshooting activities was considered a finding (FIN 50-266/301/03-02-05). Because the March 1, 2003, GT and starting diesel load test demonstrated that the G-05 GT would have been able to perform the intended 10 CFR Part 50 Appendix R function and the GT was declared inoperable when the oil analyses were returned on March 3 and 4, no violation of regulatory requirements occurred.

.3 ‘A’ MDAFW Pump Recirculation Orifice Replacement

a. Inspection Scope

During the week of March 8, 2003, the inspectors observed the post-maintenance test of the ‘A’ MDAFW pump to verify proper recirculation flow following the orifice replacement. The inspectors walked down the system and looked for changes in vibrations and weld leakage, and to ensure that sufficient flow was achieved through the new orifice design. The PMT included stroke timing of system valves and verification that the pump would meet design flow requirements.

b. Findings

No findings of significance were identified.

.4 ‘B’ MDAFW Pump Recirculation Orifice Replacement

a. Inspection Scope

During the week of March 8, 2003, the inspectors observed the post-maintenance test of the ‘B’ MDAFW pump to verify proper recirculation flow following the orifice replacement. The inspectors walked down the system and looked for changes in vibrations and weld leakage, and to ensure that sufficient flow was achieved through the new orifice design. The PMT included stroke timing of system valves and verification that the pump would meet design flow requirements.

b. Findings

No findings of significance were identified.

.5 Unit 1 TDAFW Pump Recirculation Orifice Replacement

a. Inspection Scope

During the week of March 15, 2003, the inspectors observed post-maintenance testing activities associated with the Unit 1 TDAFW pump recirculation orifice to verify proper flows following replacement. The inspectors examined the system for changes in vibration, weld leakage, and operating characteristics to ensure that sufficient flow was achieved through the new orifice design. The post-maintenance test included stroke time testing for system valves and verification that the pump could meet design flow requirements. The inspectors also reviewed the operability determination associated with the TDAFW pump steam supply valve, 1MS-2019, exceeding the maximum allowable stroke time to ensure that the AFW system remained capable of performing the intended safety function.

b. Findings

The licensee identified that the Unit 1 TDAFW pump steam supply valve from the 'B' steam generator, 1MS-2019, had not been declared inoperable and the applicable TS Action Condition, TSAC 3.7.5.A, entered after the valve failed to stroke open within the maximum allowable time limit on March 9, 2003. On the morning of March 9, as part of post-maintenance testing after the recirculation orifice replacement, procedure IT-8A, "Cold Start of Turbine-Driven Auxiliary Feed Pump and Valves; Unit 1," required the operators to time the opening stroke of 1MS-2019. The stroke time recorded for was 28 seconds, 8 seconds slower than previous times and 4 seconds beyond the maximum limit of 24 seconds. Operations shift personnel and engineers coordinating the test discussed the stroke time and decided to repeat the evolution. The valve was stroked in the open direction a second and third time. In each case, the open stroke time was recorded as 20 seconds. According to licensee procedure IT-8A, which was based, in part, on NRC Inspection Manual Part 9900, "Technical Guidance," repeat testing to verify 1MS-2019 operability was not acceptable. Subsequent to the failed March 9 stroke test, engineering personnel performed an evaluation which concluded that 1MS-2019 remained operable to perform the intended safety function. On March 10, operations personnel wrote CAP 031529, "MS-2019 OOS [Out-Of-Service] During Performance of IT-8A, TSAC Not Entered," identifying the discrepancy. Because the steam supply valve from the 'A' steam generator, 1MS-2020, remained available during the period 1MS-2019 inoperability, the inspectors concluded that the Unit 1 TDAFW pump had remained capable of performing the intended safety function. Based on no actual loss of safety function of a mitigating system having occurred, this issues was determined to have very low safety significance. This issue is dispositioned in Section 4OA7.1 of this report.

.6 Unit 2 TDAFW Pump Recirculation Orifice Replacement

a. Inspection Scope

During the week of March 15, 2003, the inspectors observed the post-maintenance test of the Unit 2 TDAFW pump to verify proper recirculation flow following the orifice replacement. The inspectors performed a system walkdown and looked for changes in vibrations and weld leakage, and to ensure that sufficient flow was achieved through the new orifice design. The PMT included stroke timing of system valves and verification that the pump would meet design flow requirements.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Delta-T Setpoint Calibration at Power

a. Inspection Scope

During the week of February 3, 2003, the inspectors observed the ΔT setpoint calibration of the Unit 2 Red channel in preparation for power uprate. During the inspection, the inspectors observed placing of bistables in the tripped position, calibration of the function Tave module, calibration of the ΔT channel, and the calibration of the $Q_U > Q_L$ Δ Flux controller to verify instrumentation and control procedure ICP 10.11, "Delta-T Setpoint Calibration at Power," adherence.

b. Findings

No findings of significance were identified.

.2 Unit 1 First Stage Pressure Channel II Calibration

a. Inspection Scope

In conjunction with the Unit 1 power uprate activities, the inspectors reviewed the surveillance test for 1-PT-485 and -486 to verify test procedure adequacy and appropriate setpoints. The inspector reviewed the as-found and as-left setpoints and the tolerance requirements for the instrumentation. The inspectors observed the communications between the instrument and control technicians performing the test and the control room staff.

b. Findings

No findings of significance were identified.

.3 Unit 2 SI Valve Inservice Test

a. Inspection Scope

During the week of February 3, 2003, the inspectors reviewed testing results associated with IT 45, "Safety Injection Valves (Quarterly) Unit 2," to determine the potential impact of back-leakage noted in the vicinity of the primary containment recirculation sump. The inspectors interviewed selected engineering personnel and reviewed current emergency core cooling boundary valve leakage data, containment leakage rate testing program bases, SI system design bases, isometric drawings of the primary recirculation sumps and associated piping, and recirculation sump isolation valve construction drawings to verify that the leakage did not impact radiological release assumptions for closed systems outside containment.

b. Findings

No findings of significance were identified.

.4 Seat Leakage Test of Diesel Air Compressor Discharge Check Valves (Quarterly)

a. Inspection Scope

During the week of March 29, 2003, the inspectors reviewed WO9709941, “Replacement of G-01 Diesel Starting Air Piping (CS to SS),” and the subsequent surveillance test for adequacy to ensure that the diesel air compressor system was returned to service correctly. The inspectors reviewed IT-100, “Seat Leakage Test of Diesel Air Compressor Discharge Check Valves (Quarterly)”, test results for the amount of air leakage per hour.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

.1 Temporary Modification 03-004, Monitoring Output of 1TC-407B Delta T SP1 Runback Bistable

a. Inspection Scope

During the week of March 22, 2003, the inspectors reviewed the WO and temporary modification package associated with the 1TC-407B Delta T SP1 Runback Bistable to determine the potential impact on plant operations and possible effects on the other unit and bistables. The inspectors reviewed the design document process and work that was performed. The inspectors reviewed CAP030951 that was written because the temporary modification did not function as expected during installation and which had been closed to a Drawing Change Notice and a WO. The inspectors questioned the plant staff about this process and reviewed the separate processes to ensure that the process did not allow closure without the actions being complete. The inspectors then reviewed CAP031860, which was written in response to the inspectors questions.

b. Findings

No findings of significance were identified.

Emergency Preparedness

EP6 Drill Evaluation (71114.06)

.1 Resident Inspector Observation of an Emergency Planning Drill (Operator Requalification)

a. Inspection Scope

During the week of March 22, 2003, the inspectors observed the operator requalification training simulator exam that required classification and notification to ensure accurate and timely notifications to the county, state, and NRC. The inspectors reviewed the completed notification forms for accuracy and observed the critique following the scenario.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns, Radiological Boundary Verifications, and Radiation Work Permit (RWP) Reviews

a. Inspection Scope

The inspectors conducted walkdowns of the radiologically protected area to verify the adequacy of radiological area boundaries and postings. Specifically, the inspectors walked down radiologically significant work area boundaries (radiation, high, and locked high radiation areas) in the PAB, radwaste area, and spent fuel pool/refuel floor. The inspectors performed confirmatory radiation surveys in selected portions of these areas to verify that these areas were properly posted and controlled in accordance with 10 CFR Part 20, licensee procedures, and TSs. The inspectors also examined the radiological conditions of work areas within those radiation, high, and locked high radiation areas to assess the adequacy of licensee implemented contamination controls. Additionally, the inspectors reviewed RWPs for general tours, the transfer of primary resin to a shielded container, and the movement of a high integrity container (HIC), containing spent resin, to a transportation/shipping cask. The RWPs were evaluated for protective clothing requirements, respiratory protection concerns, electronic dosimetry alarm setpoints, use of remote telemetry dosimetry, radiation protection (RP) hold points, and As-Low-As-Is-Reasonably-Achievable considerations, to verify that work instructions and controls had been adequately specified and that electronic dosimeter setpoints were in conformity with survey results.

b. Findings

No findings of significance were identified.

.2 Job-In-Progress Reviews, Observations of Radiation Worker Performance, and RP Technician Proficiency

a. Inspection Scope

The inspectors observed selected portions of the following radiologically significant work activities performed during the inspection and evaluated the licensee's use of radiological controls:

- Transfer of primary resin to a shielded container
- Movement of spent resin in a HIC, from a shielded storage container to a shipping cask

The inspectors reviewed the pre-job briefing package for the work evolutions, reviewed the radiological requirements for the activities, and assessed the licensee's performance with respect to those requirements. The inspectors reviewed survey records, including radiation, contamination, and airborne surveys, to verify that appropriate radiological controls were effectively utilized. The inspectors also reviewed in-process surveys and applicable postings and barricades to verify their accuracy. The inspectors observed radiation protection technician (RPT) and worker performance during the work evolutions at the job sites to verify that the technicians and workers were aware of the significance of the radiological conditions in their workplace and RWP controls/limits, and that they were performing adequately given the radiological hazards present and the level of their training.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed licensee ARs written since the last inspection (September 2002) to the date of the current inspection, which focused on access control to radiologically significant areas (i.e., problems concerning activities in High Radiation Areas (HRAs), RPT performance, and radiation worker practices). The inspectors also reviewed the "Rapid Trending Assessment for Refueling Outage, U1R27." The inspectors reviewed these documents to assess the licensee's ability to identify repetitive problems, contributing causes, and the extent of conditions; and then implement corrective actions in order to achieve lasting results.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03)

.1 Walkdowns of Radiation Monitoring Instrumentation

a. Inspection Scope

The inspectors reviewed the FSAR and performed walkdowns of selected area radiation monitors (ARMs), small article monitors, and continuous air monitors (CAMs) at the spent fuel pool, and in the PAB and the radwaste processing area. Additionally, the inspectors examined a representative number of portable radiation survey instruments staged throughout the licensee's facility to verify that those instruments had current calibrations, were operable, and in good physical condition. The inspectors also reviewed the status of repair or troubleshooting activities associated with selected radiation monitoring instruments (i.e., ARMs and portal monitors that had work request tags) to verify that instrumentation problems were being addressed in an appropriate and timely manner. The inspector performed these walkdowns to verify the instrumentation was: (1) optimally positioned, (2) in a good material condition, and (3) properly indicating area radiation levels.

b. Findings

No findings of significance were identified.

.2 Calibration, Operability, and Alarm Setpoints of Radiation Monitoring Instrumentation

a. Inspection Scope

The inspectors examined calibration and surveillance records for radiological instrumentation associated with monitoring transient high and/or very high radiation areas and instruments used for remote emergency assessment to verify that the calibrations were conducted consistent with industry standards and in accordance with station procedures.

- Charging pumps High Range ARM (1RE-134)
- Containment High Range ARM (1RE-126, 127, and 128)
- PAB, 66' elevation, Spent Fuel Pool High Range ARM, (RE-135)
- PAB, 26' elevation, Demin valve gallery ARM (RE-116)
- Post Accident Sampling Station Room ARM (2 RE-109)
- Steam Generator Blowdown tank monitor ARM (2RE-222)
- Technical Support Center, 8" elevation, ARM (RE-239)

The inspector reviewed the licensee's alarm setpoints for selected ARMs to verify that the setpoints were established consistent with the FSAR, TSs, and the station's Emergency Plan.

The inspectors discussed surveillance practices with licensee personnel and reviewed calender year (CY) 2001 - 2003 calibration records and procedures for selected radiation monitors used for assessment of internal exposure. These instruments included:

- Canberra Fastscan Whole Body Counter, #96-9686, ACK #61292

The inspectors also reviewed calibration records and procedures for those instruments utilized for surveys of personnel and equipment prior to egress from the radiologically controlled area. These instruments included:

- AMS-4 Air Monitoring System
- PCM-1B Personnel Monitor
- Gamma 40/60 Portal Monitor

Additionally, the alarm setpoints for these instruments were reviewed to verify that they were established at levels consistent with industry standards and regulatory guidance provided in Health Physics Positions No. 72 and No. 250 of NUREG/CR-5569, “Health Physics Positions Data Base.”

The inspectors evaluated the calibration procedures and CY 2001 - 2003 calibration records for selected installed radiation monitoring and portable radiation survey instruments to verify that they had been properly calibrated consistent with the licensee’s procedures. Specifically, the inspectors observed the calibrations of the following instruments:

- ARM #RE-113, 19' level PAB, RHR sump area
- Teletector Model 6112 (high range gamma)
- RSO-5 Ion chamber (low range beta-gamma)
- RM-14 radiation monitor

The inspectors also observed RPTs performing weekly functional checks of selected radiation detection instruments to verify that they had been tested consistent with the licensee’s procedures. Specifically, the inspectors observed the functional testing of the following installed radiation monitoring/detection instruments:

- Gamma 40/60 Portal Monitor
- AMS-4 Beta Particulate Air Monitor

b. Findings

No findings of significance were identified.

.3 RPT Instrument Use

k. Inspection Scope

The inspectors observed RPTs performing in-field source checks of portable radiation survey instruments to verify that those source checks were adequately completed using appropriate radiation sources and station procedures. The inspectors assessed the RPTs use of radiation/contamination detection instruments as they provided radiological job coverage for risk significant work (e.g., the transfer of primary resin to a shielded container in the radwaste area, the subsequent movement of the HIC from the shielded storage container to the transportation/shipping cask, as well as routine plant work) to ensure that the RPTs were utilizing the appropriate instruments. The inspectors monitored RPTs performing daily source checks of selected contamination monitors and small article monitors (i.e., for surveys of personnel and equipment prior to unconditional release from the radiologically controlled area to verify that they were source tested and calibrated as required by station procedures and industry standards.

b. Findings

No findings of significance were identified.

.4 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed CY 2001-2003 ARs that addressed radiation monitoring instrument deficiencies to determine if any significant radiological incidents involving instrument deficiencies had occurred. The inspectors examined the results of a self-assessment (i.e., the RP Instrumentation, PBSA-RP-02-01 and SA-RP-01-01, RP Monitoring System) that focused on the licensee's AR database and several individual ARs related to radiation monitoring instrumentation and protective equipment (i.e., self-contained breathing apparatus (SCBA)) generated during the current assessment period. The inspectors also interviewed plant staff and examined closed ARs to verify that radiological instrumentation and protective equipment related issues were adequately addressed by the licensee. The inspectors evaluated these documents to verify the licensee's ability to identify repetitive problems, contributing causes, extent of conditions, and the implementation of corrective actions to achieve lasting results.

b. Findings

No findings of significance were identified.

.5 SCBA Program

a. Inspection Scope

The inspectors reviewed the licensee's respiratory protection program for compliance with the requirements of Subpart H of 10 CFR Part 20. The inspectors performed walkdowns of the SCBA storage locations and inspected a sampling of the units to verify the material condition of the protective equipment, to ensure that it was properly maintained and stored, and to ensure that SCBAs were properly staged and ready for use. The inspectors evaluated the licensee's capability to refill and transport SCBA air bottles throughout the plant in the event of an emergency response. The inspectors examined the licensee's shiftly crew staffing (i.e., control room as well as other key emergency response personnel) of SCBA qualified personnel to verify an adequate number of plant personnel could respond in the event of an emergency. The inspectors reviewed the manufacturer-certified training/qualification of personnel allowed to perform maintenance and repairs on SCBA components vital to the unit's function. The inspectors assessed maintenance procedures governing vital component work and periodic air cylinder hydrostatic testing documentation to verify consistency between licensee procedures and SCBA manufacturer's recommended practices. The inspectors reviewed the CY 2002-2003 monthly testing records for SCBAs located in various areas within the site. Specifically, the inspectors reviewed the licensee's current SCBA training and qualification records to verify that control room personnel, fire brigade staff, and other key emergency response organization personnel were properly equipped with necessary protective equipment, currently trained, and qualified for SCBA use (including personal bottle change-out), as required by the Code of Federal Regulations, the licensee's Emergency Plan, FSAR, and plant procedures.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP4 Security Plan Changes (71130.04)

a. Inspection Scope

The inspectors reviewed revisions to the Point Beach Plant Security and Safeguards Contingency Plan to verify that changes did not decrease the effectiveness of the submitted document. The referenced revision was submitted in accordance with 10 CFR 50.54(p) by a licensee letter dated December 20, 2002.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

.1 Occupational Exposure Control Effectiveness and RCS Specific Activity

a. Inspection Scope

The inspector reviewed the licensee's determination of PI for the occupational radiation safety cornerstone (Occupational Exposure Control Effectiveness) to verify that the licensee accurately determined these PIs and had identified all occurrences required by these indicators. Specifically, the inspector reviewed the licensee's ARs for CY 2002-2003 and the 4th Quarter Occupational Exposure PI data to ensure that there were no PI occurrences that were not identified by the licensee. Additionally, as part of plant walkdowns (Section 2OS1.1), the inspector selectively examined the adequacy of posting and controls for locked HRAs, to verify the current Occupational Exposure Control Effectiveness PI.

The inspectors also reviewed the licensee's assessment of its PI for Barrier Integrity, RCS Specific Activity. No reportable elements were identified by the licensee for CY 2002, and monthly data for January, CY 2003. The inspectors compared the licensee's data with CY 2002-2003 ARs to verify that there were no occurrences concerning the Barrier Integrity, RCS Specific Activity cornerstone. Additionally, the inspectors also observed staff chemistry technicians collecting RCS samples to verify that the technicians had complied with the applicable procedures during the collection and processing of the samples.

The accuracy and completeness of all PI data was assessed against the criteria specified in Nuclear Energy Institute 99-02, Revision 2, "Regulatory Assessment Performance Indicator Guideline." The inspector interviewed members of the licensee's staff who were responsible for PI data acquisition, verification and reporting, to verify that their review and assessment of the data was adequate.

l. Findings

No findings of significance were identified.

.2 Unplanned Power Changes

a. Inspection Scope

During the week of March 31, 2003, the inspectors reviewed PI data associated with unplanned power changes for the four quarters of 2002 for Units 1 and 2. The inspectors compared the licensee's data with CY 2002 power history traces to verify that there were no other occurrences concerning unplanned power changes. The inspectors also reviewed the station logs for indications of power changes.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Reoccurring Façade Freeze Protection System Deficiencies

a. Inspection Scope

During the week of February 15, 2003, the inspectors reviewed façade freeze protection system operations to determine the adequacy of the freeze protection preparations and the effects of three freeze incidents on plant systems. The inspectors walked down selected areas of the Unit 1 and Unit 2 façades to verify proper installation of freeze protection equipment and insulation. The inspectors reviewed façade freeze protection procedures and the licensee's documentation of actions taken during the fall of 2002. As part of the investigation of the three freeze incidents that occurred on February 11, 12, and 13, 2003, the inspectors walked down the associated areas and reviewed the compensatory measures implemented to prevent a recurrence of the façade freeze problems. The inspectors reviewed freeze protection issues during the last four winter seasons to understand the similarities between the most recent issues and those of the previous years. Interviews were conducted with personnel involved with freeze protection operations to determine the licensee's overall understanding of façade freeze problems verses individual freeze incidents that had occurred during the previous 4 years.

b. Findings

Introduction

A finding of very low safety significance (Green) was identified through a self-revealing event on February 11, 2003, when one of the main control board indications associated with Unit 1 'B' main steam line pressure began reading higher that the other two. The higher pressure indicated the formation of an ice plug associated with pressure transmitter 1PT-483, which resulted in the removal of one of the three main steam line pressure inputs to the engineering safeguards system, a system relied upon to mitigate the consequences of a design basis accident.

Description

On the morning of February 11, 2003, during shift turnover walkdowns, the Duty Shift Supervisor noticed that one of the main control board indications for the Unit 1 'B' main steam line pressure transmitter, 1PT-483, indicated higher that the other two. The higher indication was caused by a freeze plug developing in the sensing line going from the main steam pipe to the associated pressure transmitter. On February 12, a reactor makeup water sample line was also found frozen when chemistry personnel attempted to take a routine sample. On February 13, a pressure gauge sensing line associated with condensate return from a steam generator blowdown system was found frozen. As a result of these indications, plant management initiated a walkdown of the façade for other areas that might be affected by the cold weather.

The inspectors reviewed the façade freeze procedures (PC-49 series) for the roles and responsibilities of licensee personnel during cold weather preparations and noted that the procedures did not give specific information or guidance to personnel responsible for associated walkdowns. During discussions with responsible individuals, the inspectors learned that there was no training to assist in the evaluation of insulation deficiencies or heat tracing requirements for freeze protection systems. As a result, individuals performing the walkdowns during cold weather preparations failed to notice insulation coverage discrepancies. Examples included the:

- Unit 1 ‘B’ main steam pressure indicator. The insulation flashing mounted on the sensing line from the main steam piping to the pressure transmitter was uncovered next to a support bracket by only a quarter of an inch. The gap was sufficient to allow the pipe support to act as a heat sink, conducting heat away from the sensing line resulting in the formation of an ice plug. Licensee insulators could have discovered the problem if they had participated in cold weather preparation walkdowns. However, since other licensee personnel had performed the walkdowns, the presence and significance of the gap was not noticed. The result was the formation of an ice plug and removal of one of the three main steam line pressure indications to the ESF system, a system relied upon to mitigate the consequences of a design basis accident.

- a pipe in the Unit 1 that drained water from underground cable conduits to a floor drain. This pipe had frozen and ruptured, spilling water onto the facade floor which resulted in large areas being covered with ice.

Analysis

Lack of façade freeze protection system coordination and overview was further evidenced by nine corrective actions for freeze incidents that were written between January 23 and February 26, 2003. Following the Unit 1 ‘B’ main steam pressure frozen indicator, the licensee dispatched operations, engineering, and insulator personnel as teams to assess the quality of insulation/freeze protection in both unit façades on February 14. The teams primarily focused on damaged/missing insulation and insulation that had metallic components (piping supports, conduit, etc.) penetrating the insulation. The walkdown resulted in thirteen new WO tags being initiated to address insulation issues that required augmentation and/or repair. These integrated team walkdowns occurred 4 months after the licensee had completed the initial walkdowns for cold weather preparations.

The inspectors determined that the most recent façade freeze protection issues represented a performance deficiency, in that, even though the licensee had taken corrective actions to address individual freeze incidents during the previous 4 years, corrective actions had been ineffective in determining all the root causes associated with façade freeze protection issues. Specifically, previous licensee corrective actions had failed to identify that cold weather preparation procedures contained insufficient guidance to personnel responsible for walkdowns and that no training was available to assist in the evaluation of insulation deficiencies or heat tracing requirements for freeze protection systems. The inspectors determined that the issue warranted a significant evaluation in accordance with Inspection Manual Chapter 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Disposition Screening,” issued on February 21, 2003.

The inspectors determined that the façade freeze protection issues were more than minor because: 1) they had affected the availability, reliability, and capability of an input to the engineering safeguards system, a system relied upon to mitigate the consequences of a design basis; and 2) if left uncorrected, they would become a more significant concern in subsequent years if freezing of sensing lines resulted in the inability to mitigate the consequences of an accident.

The inspectors used Manual Chapter 0609, Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," regarding mitigating systems and determined that the finding was not a design or qualification deficiency, did not represent an actual loss of the safety function, or meet any of the internal or external event screening criteria. Therefore, the finding screened as Green, a finding of very low safety significance.

Enforcement

Criterion XVI, "Corrective Action," of 10 CFR Part 50, Appendix B, requires, in part, that measures be established to assure that conditions adverse to quality are promptly identified and corrected and that corrective actions be taken to preclude repetition. Contrary to the above, licensee corrective actions during the previous four winter seasons failed to identify that periodic check procedure PC-49, "Cold Weather Preparation Procedure," contained insufficient lagging deficiency guidance to personnel responsible for cold weather preparation walkdowns and that a lack of training in the evaluation of insulation deficiencies and heat tracing requirements for façade freeze protection systems existed. The result was the formation of an ice plug in the sensing line associated with the Unit 1 'B' main steam line pressure transmitter, 1PT-483, on February 11, 2003, an event which removed an input to the engineering safeguards system, a system relied upon to mitigate the consequences of a design basis accident.

Since the other two Unit 1 "B" steam line pressure signals had remained operable on February 11, 2003, the engineering safeguards system remained capable of performing the intended safety function in response to a SI signal associated with a design basis event. Accordingly, this violation is being treated as a Non-Cited Violation (NCV 50-266/03-02-06) consistent with Section VI.A. of the NRC Enforcement Policy. This violation was entered into the licensee's corrective action system as CAP031085, "1PT-483 'B' SG [Steam Generator] Pressure Transmitter Failed/Sensing Line Found Frozen."

4OA4 Cross-Cutting Findings

.1 A finding described in Section 1R14.1 of this report had, as its primary cause, a human performance deficiency, in that, a lack of understanding of the basic emergency notification telephone system configuration and the absence of associated drawings and operating instructions resulted in unnecessary periods of system unavailability between December 28, 2002, and January 17, 2003.

.2 A finding described in Section 1R19.1 of this report had, as its primary cause, a human performance deficiency, in that, despite multiple opportunities for procedure writers, technical reviewers, relay technicians, maintenance work planners, electrical maintenance first-line supervisors, and operations personnel to have identified quantitative acceptance criteria limits that did not correspond to vendor recommended values, each of the four procedures used to calibrate the EDG safety-related protective relays were found to contain similar quantitative acceptance criteria errors. Between the four calibration procedures and two temporary procedure changes associated with the safety-related protective relays, the inspectors estimated that not less than 32 licensee personnel in diverse parts of the organization had an opportunity to identify the acceptance criteria errors.

.3 A finding described in Section 1R19.2 of this report had, as its primary cause, a human performance deficiency, in that, lack of interdepartmental communications and coordination caused the GT to be inappropriately returned to service on March 3, 2003, despite analyses that indicated advanced oil degradation and the onset of bearing damage in the starting diesel and no return-to-service testing requirements having been defined in the maintenance department troubleshooting plan.

.4 A finding described in Section 4AO2.1 of this report had, as its primary cause, a human performance deficiency, in that, lack of façade freeze protection system coordination and training in the areas of lagging deficiencies and façade freeze system operations resulted in the formation of an ice plug in the sensing line associated with the Unit 1 ‘B’ main steam line pressure transmitter, 1PT-483, on February 11, 2003. The result was the removal of one of the three main steam line pressure inputs to the Unit 1 engineering safeguards system, a system relied upon to mitigate the consequences of a design basis accident.

4OA6 <u>Meetings</u>

.1 <u>Exit Meeting</u>

The resident inspectors presented the inspection results to Mr. A. Cayia and other members of licensee management on April 1, 2003. The licensee acknowledged the findings presented. No proprietary information was identified.

.2 <u>Interim Exit Meetings</u>

Interim exits were conducted for:

- Safeguards Inspection with Mr. M. Fencl on January 28, 2003.
- Access Control to Radiologically Significant Areas, Radiation Monitoring Instrumentation and Protective Equipment, and Performance Indicator Verification for Occupational Exposure Control Effectiveness, and RCS Specific Activity with Mr. S. Thomas on February 14, 2003. A follow-up telephone discussion was held with the Regulatory Assurance Manager on March 21, to further discuss inspection-related topics.

4OA7 <u>Licensee-Identified Violations</u>

The following violations of very low significance were identified by the licensee and are violations of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Manual, NUREG-1600, for being dispositioned as NCVs.

Cornerstone: Mitigating Systems

Technical Specification 3.7.5. requires that if one of the two steam supply valves to the turbine-driven AFW pumps is inoperable, action condition 3.7.5.A must be entered and actions taken to restore the inoperable steam supply valve to operable status within 7 days. Contrary to the above, the licensee failed to enter TS Action Condition 3.7.5.A on March 9, 2003, after stroke time testing revealed that the Unit 1 turbine-driven AFW pump steam supply motor-operated valve from the ‘B’ steam generator, 1MS-2019, had exceeded the maximum stoke time limit in the open direction. The licensee entered this issue into the CAP as CAP031529, “1MS-2019 OOS During Performance Of IT-8A, TSAC Not Entered.”

KEY POINTS OF CONTACT

Licensee

J. Anderson, Business Group Manager
G. Arent, Regulatory Affairs Manager
J. Boesch, Maintenance Manager
A. Cayia, Site Vice-President
G. Corell, Chemistry Manager
M. Fencl, Security Manager, Kewaunee/Point Beach
F. Flentje, Senior Regulatory Compliance Specialist
D. Hettick, Performance Assessment Manager
M. Holzmann, Nuclear Oversight Manager
N. Hoefert, System Engineering Manager
R. Hopkins, Nuclear Oversight Supervisor
J. Jensen, Plant Manager
T. Kendall, Engineering Programs Manager
C. Krause, Regulatory Compliance
M. McCarthy, Engineering Recovery Manager
T. Petrowsky, Design Engineering Manager
D. Schoon, Operations Manager
C. Sizemore, Projects Training Supervisor
P. Smith, Operations Training Supervisor
J. Strharsky, Planning and Scheduling Manager
T. Taylor, Kewaunee/Point Beach Site Assessment Manager
S. Thomas, Radiation Protection Manager

Nuclear Regulatory Commission

D. Spaulding, Point Beach Project Manager, NRR
K. Riemer, Chief, Reactor Projects Branch 5

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-266/301/03-02-01	FIN	Emergency Notification System Power Failure (Section 1R14.1)
50-266/301/03-02-02	URI	Emergency Planning Organization 10 CFR Part 50.54(q); Technician Instructions, Procedures, and Drawings; Emergency Response Facility Equipment Replacements Without Licensee Knowledge; and Remote Emergency Notification Telephone System Monitoring Capability Issues (Section 1R14.1)
50-266/301/03-02-03	URI	Submerged 13.8-kV, 4160-V, and 480-V Electrical Cables (Section 1R15.2)
50-266/301/03-02-04	NCV	Emergency Diesel Generator Safety-Related Protective Relay Calibration Procedure Inadequacies (Section 1R19.1)
50-266/301/03-02-05	FIN	G-05 Gas Turbine Generator Return-to-Service Prior to Completion of Troubleshooting and Maintenance Activities (Section 1R19.2)
50-266/301/03-02-06	NCV	Reoccurring Facade Freeze Protection System Deficiencies (Section 4OA2.1)

Closed

50-266/301/03-02-01	FIN	Emergency Notification System Power Failure (Section 1R14.1)
50-266/301/03-02-04	NCV	Emergency Diesel Generator Safety-Related Protective Relay Calibration Procedure Inadequacies (Section 1R19.1)
50-266/301/03-02-05	FIN	G-05 Gas Turbine Generator Return-to-Service Prior to Completion of Troubleshooting and Maintenance Activities (Section 1R19.2)
50-266/301/03-02-06	NCV	Reoccurring Facade Freeze Protection System Deficiencies (Section 4OA2.1)

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
ALARA	As Low As Is Reasonably Achievable
AR	Action Request
ARM	Area Radiation Monitor
CAM	Continuous Air Monitor
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CST	Condensate Storage Tank
CY	Calendar Year
DBD	Design Basis Document
DC	Direct Current
DMIMS	Digital Metal Impact Monitoring System
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
ENS	Emergency Notification System
EOF	Emergency Operations Facility
EP	Emergency Plan
EPRI	Electric Power Research Institute
ERF	Emergency Response Facility
FSAR	Final Safety Analysis Report
gpm	Gallons Per Minute
GT	Gas Turbine
HIC	High Integrity Container
HRA	High Radiation Area
IT	Inservice Test
ITS	Improved Technical Specification
IST	Inservice Test(ing)
kV	Kilovolt
LER	Licensee Event Report
LOAC	Loss of All Alternating Current
LONF	Loss of Normal Feedwater
MDAFW	Motor-Driven Auxiliary Feedwater
MSSV	Main Steam Safety Valve
NCV	Non-Cited Violation
NP	Nuclear Plant Business Unit Procedure
NRC	Nuclear Regulatory Commission
OS	Occupational Reactor Safety
OWA	Operator Workaround
PAB	Primary Auxiliary Building
P&ID	Piping and Instrumentation Diagram
PBF	Point Beach Form
PC	Periodic Check
PI	Performance Indicator
PMT	Post-Maintenance Testing
psig	Pounds Per Square Inch - Gauge
RCA	Radiologically Controlled Area

RCS	Reactor Coolant System
RHR	Residual Heat Removal
RMP	Routine Maintenance Procedure
RP	Radiation Protection
RPT	Radiation Protection Technician
RWP	Radiation Work Permit
SBCC	Site Boundary Control Center
SCBA	Self Contained Breathing Apparatus
SI	Safety Injection
SR	Surveillance Requirement
SW	Service Water
TDAFW	Turbine-Driven Auxiliary Feedwater
TS	Technical Specification
U1R27	Unit One Refueling Outage 27
URI	Unresolved Item
V	Volt
WO	Work Order

LIST OF DOCUMENTS REVIEWED

1R04 Equipment Alignment

Operating Instruction OI 106; Façade Freeze Protection Procedure; dated December 9, 2002; Revision 19

FF-E-500D; Unit 1/Unit 2 FF [Façade Freeze Protection] Drawing Matrix

WE FF-M-618; Façade Freeze Protection RE-211/212 Rad Sample Room Piping; Unit 2, dated December 4, 2000

WE FF-M-511; Façade Freeze Protection “A”-Loop Main Steam Pressure Transmitters; Unit 1, dated December 4, 2000

WE FF-M-616; Façade Freeze Protection Refueling Water Storage Tank and Piping; Unit 2, dated December 4, 2000

WE FF-M-609; Façade Freeze Protection “B”-Loop Main Steam Pressure Transmitters; Unit 2, dated December 4, 2000

WE FF-M-610; Façade Freeze Protection “A”-Loop Main Steam Pressure Transmitters; Unit 2, dated December 4, 2000

WE FF-M-519; Façade Freeze Protection RMW [Reactor Makeup Water] Pumps P-23A & P-23B, Sump Pumps P-68A & P-68B and Piping; Unit 1, dated December 4, 2000

Design Basis Document DBD-07; Main Steam and Steam Dump System Design Bases Document; Revision 0

PBF-7040a; Walkdown Checklist Mechanical Systems/Components; Revision 0

DBD-03; Condensate and Feedwater Design Bases Document; Revision 1

Bech 6118 M-217 Sh.1; P&ID [Piping and Instrumentation Diagram] for Auxiliary Feedwater System; Unit 1 & 2 Revision 13

Bech 6118 M-217 Sh.2; P&ID for Auxiliary Feedwater System; Unit 1 & 2 Revision 18

DBD-01; Auxiliary Feedwater, Section 4.12; Revision 0

Unit 2 Infrared Inspection Results, 2AF101 and 2AF100 Auxiliary Feedwater Injection Piping; July 8, 1999

Periodic Check Procedure PC-8 part 2; Monthly AFW Pump Discharge Piping Temperature Checks; Revision 3

CAP031777; 2P-29 Turbine Driven Auxiliary Feedwater Pump Discharge Piping Noise; March 22, 2003

CAP031815; Insulation Missing; March 25, 2003

1R05 Fire Protection

Point Beach Nuclear Plant Fire Hazards Analysis Report, Fire Zones 108, 109, 128, 129, 130, 216, 304, and 692; August 17, 2001

ASTM E-84; Surface Burning Characteristics of Building Material

1R07 Heat Sink Performance

EPRI NP-7552; Heat Exchanger Performance Monitoring Guidelines; December 1991

EPRI TR-107397; Service Water Heat Exchanger Testing Guidelines; March 1998

OPR000046; GL 89-13 fouling issues with HX-105A & B - PAB Battery Room Coolers; dated February 24, 2003

CAP031246; Macro-Fouling expected on shell side of SFP H/Xs based on SW flow data, dated February 20, 2003

1R11 Licensed Operator Qualifications

SES 081; Simulator Scenario for License Operator Requalification Training, (Loss of Coolant Accident); Revision 0

SG0122; Simulator Scenario for Licensed Operator Requalification Training, (Loss of All AC Power); dated March 10, 2003

TI 8.0; Conduct of Simulator training And Simulator Evaluation, Attachment 4; Unit 0, Revision 4

1R12 Maintenance Rule Implementation

Point Beach Nuclear Plant Maintenance Rule Unavailability Data Sheet, Service Water; Unit 0, dated January 1, 2001, through January 1, 2003

Point Beach Nuclear Plant Maintenance Rule Unavailability Data Sheet, Component Cooling Water; Unit 0, dated January 1, 2001, through January 1, 2003

CAP031847; Conservative Error in System MTN Rule Unavailability Hours For 1st Qtr 2002; dated March 26, 2003

4th Quarter 2002 Service Water System (a)(1) Classification Summary; dated January 22, 2003

CAP029327; Through-wall Leakage, HX 12C Service Water Blow-down Line; dated September 15, 2002

CAP005363; Service Water Zurn Strainer Inoperable; dated June 26, 2001

CAP 02315; 1SW-2907 Did Not Close During Testing; dated February 26, 2002

CAP014411; Maintenance Rule Functional Failure of 1FIC-609; dated October 11, 2001

CA007312; Maintenance Rule Functional Failure of 1FIC-609; dated October 16, 2001

CAP031726; Unit 2 CC System Temperature Exceeds 105 Degrees F for Two Minutes; dated March 3, 2003

1R13 Maintenance Risk Assessment and Emergent Work Evaluation

E-1 Report for V09A1 (Work Week Schedule), December 29, 2002

E-1 Report for V10B1 (Work Week Schedule), January 5, 2003

E-1 Report for W02B1 (Work Week Schedule), February 2, 2003

E-1 Report for W04B2 (Work Week Schedule), February 16, 2003

Daily Update of Core Damage Risk Profile (Safety Monitor), December 29, 2002 - March 31, 2003

IT 21; Charging Pumps and Check Valve Test (Quarterly) Unit 1; Revision 12

O-PT-FP-002; Monthly Diesel Engine-Driven Fire Pump Functional Test; Revision 1

DBD-T-40; Fire Protection/Appendix R, Sections 7.3 and 7.4; Revision 0

IT-115; Instrument Air Valves (Quarterly) Unit 2; Revision 16

IT 04E; Manual Stroke of Low Head Safety Injection Valves (Quarterly) Unit 2; Revision 4

WO 0207637; Inspect Inertia Latch on Breaker B52-DB50-077; dated July 3, 2002

CAP030659; Error In Safety Monitor Model, Error in DC Alignment In Safety Monitor; January 9, 2003

CAP031681, Activities Missed In On-Line Risk Evaluations; March 17, 2003

CAP031709; Safety Monitor Scheduled Activities For Week W02 Missing 2P2A; March 19, 2003

CAP031202; Safety Monitor “Planned” Scheduled Activities On the Risk Profile Incorrect; February 19, 2003

CAP031233; NP 10.3.7 Not Followed, Safety Monitor Unavailability Project Inaccurate; February 20, 2003

CAP031146; K-2B IA [Instrument Air] Compressor Constant Run Mode Pressure Switch Inop; February 13, 2003

CAP031302; Unforseen Increase In Risk; February 24, 2003

1R14 Personnel Performance During Non-Routine Plant Evolutions

WO 0301725; Replace Battery Chargers Associated with the 48 VDC Power Supply to the ENS in the SBCC; dated January 14, 2003

SCR 2003-0027; 10 CFR50.59/72.48 Screening for Replace Battery Charger Associated with 48 VDC Supply to ENS Located in the SBCC; Revision 1

CAP030676; Loss of 48 VDC power to the SBCC Emergency Notification System phones; dated January 10, 2003

CAP030568; Power Lost to Site Boundary Control Center and Emergency Information Center; dated December 28, 2003

CAP030588; Loss of ENS Phones; dated December 31, 2003

CAP030589; NRC 8 Hour Non-Emergency Notification Made Due to ENS Phones OOS; dated January 1, 2003

CAP030903; PBNP 1.4% MUR Uprate NRC SES Not Consistent with Implementation Plans; dated January 28, 2003

1R15 Operability Evaluations

OPR-000044; MSSV Setpoint Tolerance Was Not Included in MDAFW Pump IST [Inservice Testing] Acceptance Criteria Calculation; Revision 0

OPR-000044; MSSV Setpoint Tolerance Was Not Included in MDAFW Pump IST Acceptance Criteria Calculation; Revision 1

IT 10; Test of Electrically-Driven Auxiliary Feed Pumps And Valves (Quarterly); Revision 46

IT 10A; Test of Electrically-Driven Auxiliary Feed Pumps And Valves With Flow To Unit 1 Steam Generators (Quarterly); Revision 14

IT 10B; Test of Electrically-Driven Auxiliary Feed Pumps And Valves With Flow To Unit 2 Steam Generators (Quarterly); Revision 13

Point Beach Calculation N-94-158; Verification of Required AFW Pump Differential Head For Accident Flow Rate; dated November 15, 1994

Point Beach Calculation 98-0103; Determination of Acceptance Criteria for Main Steam Safety Valve Setpoint Tests; dated July 10, 1998

Point Beach Calculation 96-0244; Minimum Allowable IST Acceptance Criteria for Turbine and Motor-Driven AFW Pump Performance; dated October 31, 1996

CAP031002; Analysis for Aux Feed Pumps dP Is Non Conservative for IST Test Criteria; dated February 5, 2003

Westinghouse Letter WEP-02-1; Nuclear Management Company, Point Beach Units 1 & 2, Increased Pressure Drop Between the SG and MSSV's; dated January 16, 2002

FSAR Section 14.1.10; Loss of Normal Feedwater; June 2001

FSAR Section 14.1.11; Loss of All AC Power to the Station Auxiliaries; June 2001

FSAR Section 10.2; Auxiliary Feedwater System; June 2002

DBD 01; Auxiliary Feedwater System, Motor-Driven AFW Pump (P-38A) Performance Curve (1969); Revision 3 DRAFT

DBD 01; Auxiliary Feedwater System, Motor-Driven AFW Pump (P-38B) Performance Curve (1969); Revision 3 DRAFT

Point Beach Nuclear Plant Setpoint Document; Section 14.11, Auxiliary Feedwater; May 14, 2002

Point Beach Cross-Reference Report; NUREG-1431 Section 3.07.01 ITS to CTS; dated November 13, 1999

Point Beach Cross-Reference Report; NUREG-1431 Section 3.07.01 CTS to ITS; dated November 13, 1999

Point Beach Letter NRC 2000-0465; Dockets 50-266 and 50-301 Supplement 7 to Application For Amendment To Facility Operating License Appendix A: Technical Specifications Improvement Project Response to RAI On ITS Section 3.6; Response to RAI ON ITS Sections 3.7.4 and 3.7.5, Point Beach Nuclear Plant, Units 1 and 2; October 19, 2000

Point Beach Letter NRC 2001-004; Dockets 50-266 and 50-301 Supplement 10 to Application For Amendment To Facility Operating License Appendix A: Technical Specifications Improvement Project Response to RAI On ITS Section 3.7, Point Beach Nuclear Plant, Units 1 and 2; February 23, 2001

MSSV Testing Valve Data Results; 1999 to 2001; February 2003

Wyle Laboratories Test Procedure 1097; Testing of Crosby Spring-Operated Main Steam Safety Relief Valves for Wisconsin Electric Power Company, Point Beach Nuclear Plant; September 21, 1997

Wisconsin Electric Power Company Letter of Implementation of NUREG-0737 and Reg Guide 1.97; dated September 1, 1983

CAP030790; Raceway Separation Requirements Are Met for CST Level Indication on Both T-24A & B; dated January 21, 2003

CAP030861; The Basis For Calling CST Level Indication Operable Needs Revisited; dated January 24, 2003

OPR000039; CST Level Transmitter Cable Separation Issue; dated January 25, 2003

CAP031031; Potential Failure to Meet Station Blackout Commitment; dated February 7, 2003

NUMARC 87-00; Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors; dated August 1991, Revision 1

FSAR, Appendix A, Station Blackout; dated June 2002

NRC SES SBO; Station Blackout Rule, NCR SES, 10 CFR 50.63; dated October 3, 1990

PC 29; Monthly Gas Turbine & Auxiliary Diesel Load Test; Unit 0, Revision 35

CAP030776; Frequent DMIMS Alarms On Channel 754, “A” S/G Primary, With No Audible Impact; January 20, 2003

Condition Evaluation CE01114; Frequent DMIMS Alarms On Channel 754, “A” S/G Primary, With No Audible Impact; January 22, 2003

Alarm Response Book 1C20 B 4-4; Unit 1 or 2 Loose Parts Monitoring System; Revision 3

WO 0302196; VBM-00754, HX-1A SG Primary Loose Parts Signal Conditioner, March 5, 2003

ICP 06.079; Digital Metal Impact Monitoring System; Revision 1

CAP030686; G-02 EDG STL01 Relay Fails To Reposition When G-02 Secured Per TS-82; January 12, 2003

Point Beach Drawing EMD 8413730, Sheet 22; Schematic Diagram Diesel Generator G02 Start No. 1 Circuitry Point Beach N.P. Unit 1 & 2; Revision E

Point Beach Drawing EMD 8413730, Sheet 25; Schematic Diagram Diesel Generator

G02 Annunciator Part-2 Point Beach N.P. Unit 1 & 2; Revision E

Point Beach Drawing EMD 8413730, Sheet 21; Schematic Diagram Diesel Generator G02 DC Control Point Beach N.P. Unit 1 & 2; Revision E

Point Beach Drawing EMD 8413730, Sheet 23; Schematic Diagram Diesel Generator G02 Start No. 2 Circuitry Point Beach N.P. Unit 1 & 2; Revision E

CAP030621; Unit 1 “D” Electro-Hydraulic (EH) Accumulator Seal Failure; January 4, 2003

WO 0301729; Electro-Hydraulic Fluid Reservoir; January 13, 2003

WO 9945732; Electro-Hydraulic Fluid Accumulator, Inspect and O-Ring Replacement; October 8, 2002

Akzo Nobel Fluid Analysis Reports; Unit 1 Fyrquel EHC Reports; January 2, 2003, and March 11, 2003

Akzo Nobel Fluid Analysis Report; Unit 2 Fyrquel EHC Report; January 2, 2003

Point Beach System Health Check; Point Beach #1, Fyrquel EHC Fluid Characteristics; July 30, 2002, and January 17, 2003

OPR000048; 480V and 4160V Cable Issues; Revision 0

Operability Determination for CR 98-2030; 5kV Cable Found With Unusual Jacket Discoloration; May 18, 1998

Point Beach Email Correspondence With 4160 Volt Cable Vendor; Information Request Form; February 28, 2003

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Point Beach Material History Database; 480 Volt Cable ZE2B34BB, P-32F Service Water Pump, Manhole No. 1; Screen Print dated March 4, 2003

Point Beach Material History Database; 480 Volt Cable ZE1B11CD, P-32B Service Water Pump, Manhole No. 1; Screen Print dated March 4, 2003

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Point Beach Material History Database; 480 Volt Cable ZF1B20CA, P-32C Service Water Pump, Manhole No. 2; Screen Print dated March 4, 2003

Point Beach Material History Database; 4160 Volt Cables 1A36A, 1A36B, 1A36C, 1A36D, 1A36E, 1A36F, 1X-04 Transformer, Manhole No. 3; Screen Print dated March 4, 2003

Point Beach Material History Database; 4160 Volt Cables 1A56A, 1A56B, 1A56C, 1A56D, 1A56E, 1A56F, 1X-04 Transformer, Manhole No. 3; Screen Print dated March 4, 2003

Point Beach Material History Database; 4160 Volt Cables 2A45A, 2A45B, 2A45C, 2A45D, 2A45E, 2A45F, 2X-04 Transformer, Manhole No. 4; Screen Print dated March 4, 2003

Point Beach Material History Database; 4160 Volt Cables 2A47A, 2A47B, 2A47C, 2A47D, 2A47E, 2A47F, 2X-04 Transformer, Manhole No. 4; Screen Print dated March 4, 2003

Point Beach Material History Database; 13.8 kV Cables H32A1, H32A2, H32B1, H32B2, H32C1, H32C2, 2X-04 Transformer, Manhole No. 18; Screen Print dated March 4, 2003

Point Beach Material History Database; Cable Designation A01, Basic Characteristics Including Cable Shield Material Information; Screen Print dated March 4, 2003

Point Beach Material History Database; Cable Designation K23, Basic Characteristics Including Cable Shield Material Information; Screen Print dated March 4, 2003

Point Beach Material History Database; Cable Designation M02, Basic Characteristics Including Cable Shield Material Information; Screen Print dated March 4, 2003

Specification For 5 kV and 15 kV Insulated Power Cable; Point Beach Nuclear Plant, Wisconsin Michigan Power Company; November 27, 1967 - Revision 1

CAP031655; 4160V Cables Possibly Beyond End Of Life; March 14, 2003

CAP031417; Water Intrusion In Cable Vaults; March 3, 2003

CAP030253; Living With Adverse Conditions Related To Cold Weather: Not Fixing The Cause; November 27, 2002

CR 96-1602; Electrical Penetration In The SW Corner Of The Unit 1 Facade Has A Seal Leaking A Steady Stream Of Water Onto the Cable Tray. Ice has formed; December 5, 1996

CR 97-0906; Massive Formation of Ice Has Collected On the Cable Tray in the Southwest Corner of the Unit 1 Facade; March 22, 1997

CR 97-1497; North Circulating Water Pump Manhole Does Not Have a Means to Be Pumped; May 6, 1997

CR 97-3200; The Cable To 1P-30B Circulating Water Pump Is Grounded On 'C' Phase Core Conductor and The Shields on A and C Phases Are Grounded Due To Outer Cable Jacket Degradation. Installed Cables Are 350 MCM. S&L Shows The Cables Being 500 MCM; October 4, 1997

CR 97-3231; Manhole No. 1 Is filled With Water Possibly Causing A Grounding Problem With The Cable for 1P-30B Circulating Water Pump. Manholes 10, 14, and 19 Are Also Flooded; October 7, 1997

CR 97-3398; The Grounded Cable to 1P-30B Was Found To Have Failed Approximately 2 Feet West Of Manhole #1. Moisture Was Trapped Between The Outer Jacket And Shield The Full length Of The Cable; October 16, 1997

CR 97-3465; The Power Cable To 1P-30A Circulating Water Pump Has Grounded Shield On B and C Phases. The Core Conductor Was Meggered And Found To Be OK For Service; October 21, 1997

CR 97-3541; Over The Last Number of Years, Operations Personnel Have Noted An Increase in the Amount of Ground Water Leaking Into the Northern Side of the Plant; October 27, 1997

CR 97-3592; Manhole #10 Is Filled With Water Again; November 1, 1997

CR 98-1520; Ground Water Is Leaking Into The U-1 and U02 RHR Valve Galleries on the -19ft Level Of The PAB; April 10, 1998

CR 98-1700; Manholes Near Pumphouse Are Filled With Water to Within Approximately 18 Inches Of Cover; April 24, 1998

CR 98-3024; An Intrusion Alarm Was Received on the Cover For Manhole #1. This Was Caused By Operations Fire Pump Test; April 4, 1998

CR 98-3760; On 10/28/98, Security Received a Hard Alarm On Manhole #1. This Is a Re-occurring Problem With Water Filling the Manhole Causing Alarms. Previous Occurrences 4/28/98, 8/1/98, 8/4/98, 8/16/98; October 30, 1998

CR 00-1901; The Underground Cable Runs Between the Circulating Water Pump House and the Plant Are Submerged in at Least 6 Feet Of Water; June 22, 2000

CAP024415; 5kV Cable Found With Unusual Jacket Discoloration; May 18, 1998

1R16 Operator Workarounds

Operator Workaround Summary; 0-02R-004 FO; March 12, 2003

NP 2.1.4; Operator Workarounds; Revision 1

Operations Department Operator Workaround Meeting Minutes; August 2002 to February 2003

Drawing Bech 6118 M-219, Sheet 2; P&ID Fuel Oil System Diesel Generator Building, Point Beach Nuclear Plant Unit 1 & 2; Revision E

Drawing Bech 6118 M-219, Sheet 3; P&ID Fuel Oil System Diesel Generator Building, Point Beach Nuclear Plant Unit 1 & 2; Revision E

Operator Challenge 0-02R-004 FO; LIT 3978, T-173 Fuel Oil Receiving Tank Level Indicator Is Out Of Calibration and Cannot Be Calibrated; March 12, 2003

Point Beach Operations Department Performance Indicator; Total Operator Burden Summary; September 2002 to February 2003

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List Of Control Board Deficiencies; March 26, 2003

List Of Lit Annunciators; March 26, 2003

1R17 Permanent Plant Modifications

10CFR 50.59 Screening; MR 03-003 Replacement of Obsolete Valve GT-9545 and Associated Piping; dated January 17, 2003

Plant Design Change Package; MR 03-003 Replacement of Obsolete Valve GT-9545 and Associated Piping; dated January 15, 2003

WO 0301833; P-503 GT GEN FUEL OIL PUMP DISCHARGE RELIEF; dated January 17, 2003

WO 0301833 Addendum 1; P-503 GT GEN FUEL OIL PUMP DISCHARGE RELIEF, Addendum 1; dated January 18, 2003

1R19 Post-Maintenance Testing

RMP 9043-12; Emergency Diesel Generator G-01 Safety Related Protective Relay Calibration; Revision 4

RMP 9043-22; Emergency Diesel Generator G-02 Safety Related Protective Relay Calibration; Revision 3

RMP 9043-32; Emergency Diesel Generator G-03 Safety Related Protective Relay Calibration; Revision 4

RMP 9043-42; Emergency Diesel Generator G-04 Safety Related Protective Relay Calibration; Revision 3

Temporary Procedure Change 2002-0074; Emergency Diesel Generator G-02 Safety Related Protective Relay Calibration, Correct Data Sheet 5; February 15, 2002

Temporary Procedure Change 2002-0452; Emergency Diesel Generator G-04 Safety Related Protective Relay Calibration, Data Sheet 6 - Delete Calibrations at 10A to 30A on 87 Device, Not Required Per ABB Instruction; July 19, 2002

RMP 9043-31; Emergency Diesel Generator G-03 2 Year Electrical Inspection; Revision 4

RMP 9043-33; Emergency Diesel Generator G-03 Mechanical Inspection; Revision 4

RMP 9043-37; Emergency Diesel Generator G-03 Maintenance Run and Post Maintenance Testing; Revision 3

RMP 9043-39; Emergency Diesel Generator G-03 Local and Remote Meter Calibration; Revision 3

ICP 13.007B-1; Emergency Diesel Generator G-03 Calibration Procedure; Revision 4

WO 0203455; G-03 Emergency Diesel Generator; January 10, 2003

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WO 0215011; G-03 EDG Crankcase Pressure Switch, January 10, 2003

WO 9946361; G-03 Emergency diesel generator Calibration Procedure, ICP-13.007B-1; January 10, 2003

Nuclear Power Business Unit Setpoint Document 21.1, Sheet 12; Protective Relay Setpoints: Emergency Diesel Generator G01; Revision 4

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