January 29, 2003

EA-02-032

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 50-266/02-13; 50-301/02-13

Dear Mr. Cayia:

On December 28, 2002, 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 January 6, 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). Three of these issues were determined not to involve a violation of NRC requirements. The fourth issue was determined to involve a violation of NRC requirements. However, because the violation was non-willful and non-repetitive and because it was entered into your corrective action program, the NRC is treating this issue as a Non-Cited Violation, 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.

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 (ICMs) required by the February 25th Order. Phase 1 of TI 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 ICMs 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 Publicly Available Records (PARS) component of 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 50-266/02-13; 50-301/02-13

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REGION III

Docket Nos:	50-266; 50-301
License Nos:	DPR-24; DPR-27
Report No:	50-266/02-13; 50-301/02-13
Licensee:	Nuclear Management Company, LLC
Facility:	Point Beach Nuclear Plant, Units 1 & 2
Location:	6610 Nuclear Road Two Rivers, WI 54241
Dates:	October 1 through December 28, 2002
Inspectors:	P. Krohn, Senior Resident Inspector M. Morris, Resident Inspector J. Adams, Senior Resident Inspector, Prairie Island C. Brown, Resident Inspector, Clinton M. Kunowski, Project Engineer R. Langstaff, Senior Reactor Inspector J. Lara, Senior Resident Inspector, Kewaunee T. Madeda, Physical Security Inspector D. NcNeil, Senior Operations Specialist D. Nelson, Radiation Specialist F. Ramirez, Reactor Engineer S. Sanders, Reactor Operations Engineer, Office of Nuclear Reactor Regulation R. Schmitt, Radiation Specialist
Approved by:	Kenneth Riemer, Chief Branch 5 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000266-02-13, IR 05000301-02-13; Nuclear Management Company, LLC; on 10/01-12/28/02, Point Beach Nuclear Plant; Units 1 & 2. Adverse Weather, Surveillance Testing, Identification and Resolution of Problems, Event Followup.

This report covers a 3-month period of baseline resident inspection and announced inservice, reactor pressure vessel head, physical security, operator licensing, fire protection, and radiation protection inspections. The inspection was conducted by the resident inspectors, inspectors from the Region III office, and an inspector from the Office of Nuclear Reactor Regulation. Three Green findings and one Green finding that was a Non-Cited Violation were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. <u>Inspection Findings</u>

Cornerstone: Initiating Events

Green. Units 1 and 2. A finding of very low significance was identified for not sufficiently coordinating and being adequately prepared for the onset of cold weather prior to November 1, 2002, a point at which the Point Beach Nuclear Plant had experienced 30 hours of below freezing temperatures over 6 nights. The primary cause of this finding was related to the cross-cutting area of human performance. Despite beginning freeze protection activities at an appropriate time, lack of coordination between licensee departments resulted in incomplete preparations prior to the onset of freezing temperatures.

The inspectors determined that the issue was more than minor because it increased the likelihood of those events that upset plant stability during power operations and would, if left uncorrected, become a more significant safety concern in subsequent years if more safety-related systems were to be affected. The finding was of very low safety significance because no safety-related functions or mitigating systems were rendered inoperable. No violation of NRC requirements occurred. (Section 1R01.1)

Green. Unit 1. The inspectors identified a finding of very low safety significance concerning the failure of a technician to properly calibrate feedwater controller LM-463F. The primary cause of this finding was related to the cross-cutting area of human performance in that the technician who performed the calibration, because of inattention to detail, did not restore a dial setting after taking three as-found readings, adjusting two potentiometers, and taking three as-left readings.

The inspectors determined that the error in calibrating the steam generator level system controller, an error that affected both generators, was of more than minor significance in that it was associated with the human performance attribute of the initiating events cornerstone and affected the cornerstone objective of limiting the likelihood of those events (such as a loss of feedwater) that upset plant stability. The finding was of very low significance because the finding did not contribute to the likelihood of a primary or secondary system loss-of-coolant accident initiator, did not contribute to the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available, and did not increase the likelihood of a fire or internal/external flood. No violation of NRC requirements occurred. (Section 1R22.1)

Green. Units 1 and 2. One finding of very low risk significance was identified by the inspectors for the licensee's failure to establish timely and adequate corrective actions to address the flooding of manholes which contained both safety and non-safety related systems, structures, and components. The inspectors identified that the licensee had not implemented effective corrective actions to address long-standing problems with flooding in manholes and had deferred the implementation of corrective actions with insufficient basis.

The finding was more than minor because, if left uncorrected, it would become a more significant concern since the lack of effective corrective actions to inspect and pump out water in manholes could affect safety-related cables routed through manholes such as those for service water pumps. Additionally, some of the cables routed in manholes provide power to safety-related buses from the licensee's offsite power systems. Hence, the loss of such power, due to cable failures, could result in momentary loss of power to the bus and the inability to re-energize the affected buses from the normal power source. This issue was categorized as a finding of very low risk significance since the identified water intrusion conditions had not caused any safety-related equipment failures at this time. No violation of NRC requirements occurred. (Section 4OA2.1).

Cornerstone: Barrier Integrity

Green. Unit 2. The inspectors identified a Non-Cited Violation of Technical Specification 3.4.10 for the operation of Unit 2 from December 2000 to April 2002 with one inoperable pressurizer safety valve. The primary cause of this finding was related to the cross-cutting area of human performance, in that, inattention to the job-at-hand resulted in a vendor reassembling the valve such that it would not have lifted at the required setpoint.

The inspectors determined that the issue was more than minor because it affected the functionality of the reactor coolant system pressure boundary, a physical barrier designed to protect the public from radionuclide releases caused by accidents or events. However, the finding was of very low risk significance since the change in core damage frequency as a result of having operated with the inoperable safety valve was determined to be less than 1E-6/year. (Section 4AO3.1)

B. <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. 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 in refueling outage U1R27. Unit 1 achieved criticality on October 16, 2002, and returned to full power on October 20. Unit 1 remained at full power until October 21, when power was reduced to 90 percent for enthalpy rise hot channel factor concerns. Following resolution of the channel factor concerns on October 22, power remained at 90 percent to resolve electro-hydraulic turbine control system issues. Power was further reduced to 84 percent on October 24 in support of turbine control system troubleshooting efforts. Unit 1 returned to full power on October 25 and remained there until November 20 when power was reduced to 98 percent to accommodate a plant process computer system software update. Unit 1 returned to full power later the same day and remained there until December 28 when power was reduced to 53 percent in support of 1P28A main feed pump maintenance and main turbine stop valve, atmospheric steam dump, condenser steam dump, and crossover steam dump testing. At the end of this inspection period, December 28, Unit 1 remained at 53 percent power. Unit 1 returned to full power on December 29.

Unit 2 began the inspection period at full power and remained there until October 24, when power was reduced to 98 percent on two occasions for auxiliary feedwater pump testing. Unit 2 returned to full power on October 25 and remained there until October 26 when power was reduced to 65 percent for main turbine stop valve, atmospheric steam dump, condenser steam dump, and crossover steam dump testing. Unit 2 returned to full power on October 27 and remained there until November 18 when power was reduced to 98 percent for a plant process computer system malfunction and scheduled maintenance. Unit 2 returned to full power later the same day and remained there until December 28 when power was reduced to 98 percent to support work on a plant process computer system multiplexer. At the end of this inspection period, December 28, Unit 2 remained at 98 percent power. Unit 2 returned to full power on December 29.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

.1 Insufficient Preparation for Cold Weather Conditions

b. Inspection Scope

During the weeks of October 28 and November 4, 2002, the inspectors reviewed the licensee’s cold weather readiness to verify that cold weather protection features such as heat tracing (the facade freeze protection system) and space heaters were monitored and functional; that plant features and procedures for circulating water intake ice melt operations were appropriate; and that operator actions specified in the licensee’s cold weather preparation procedures verified the readiness of essential systems. As part of this effort, the inspectors performed freeze protection walkdowns in the Unit 1 and Unit 2 facade structures; the G03 and G04 emergency diesel generator (EDG) rooms; the EDG fuel oil transfer pump rooms; portions of the primary auxiliary, turbine, and circulating water pump house buildings; and a water pre-treatment trailer to determine the preparedness of plant areas and equipment for cold weather. The inspectors also verified that the licensee had entered weather-related problems, which could affect mitigating systems and support systems, in their corrective action program (CAP) and that the problems were being properly addressed for resolution.

b. Findings

A Green finding (FIN) was identified for not sufficiently coordinating and being adequately prepared for the onset of cold weather prior to November 1, 2002, a point at which the Point Beach Nuclear Plant (PBNP) had experienced 30 hours of below freezing temperatures over 6 nights.

On October 31, the inspectors contacted the freeze protection system engineer and asked for a list of outstanding facade freeze protection issues for the approaching winter season. A list of 22 items was provided, having been generated from operations performance of Periodic Check Procedure (PC) 49, "Cold Weather Preparations," Revision 2, and Operating Instruction (OI) 106, "Facade Freeze Protection," Revision 18. These procedures had been begun on October 1, 2002, and were completed by October 15. The deficiencies from the periodic checks and operating instruction were combined and provided to the Fix-It-Now team on or about October 21. During a plant status meeting on October 31, plant management expressed displeasure with the status of cold weather preparations and directed that increased resources and an issue manager be assigned to work the freeze protection issues to closure. The issue manager researched the work order (WO) system and interviewed maintenance, engineering, and operations personnel. On November 6, the issue manager determined that there had been 44 items requiring freeze protection attention and began aggressively pursuing closure of each item. Selected items included:

- Availability/reliability of circulating water intake crib resistance temperature detectors (RTDs). The RTDs are used during ice melt operations to determine the effectiveness of preventing circulating water system freezing and frazil ice formation. Three of the six RTDs had been out-of-service since early April 2002 but were repaired and returned to service by November 26. However by the end of this inspection period, on December 28, three of the six RTDs again demonstrated unreliable operations by indicating either low or erratically.

- Missing or damaged lagging or insulation. Despite a previous December 2001 NRC finding concerning restoration of piping insulation following maintenance activities, 5 of 22 items on the freeze protection engineer's initial list pertained to lagging. One of the 5 lagging items could have affected the operation of a safety-related refueling water storage tank level transmitter.

- The degraded material condition of the circulating water pump house trash rack wind curtains. In extreme weather conditions, the degraded wind curtains could have allowed the accumulation of ice on the circulating water system traveling screens and trash racks causing a challenge to the suction supply of the safety-related service water (SW) pumps.

- A water pre-treatment trailer. The trailer required additional heater, door closure, and heat trace upgrades to ensure the ability to withstand local low temperature extremes. Unavailability of the pre-treatment trailer could have resulted in secondary system water inventory challenges and potential chemistry excursions due to reduced steam generator blowdown capabilities.

- Reduced heating capacity of the Unit 2 refueling water storage tank. One of the six heaters had been out-of-service since February 2002. Although sufficient heating capacity remained to prevent the contents of the tank from freezing, the inspectors determined that the licensee had not taken the opportunity to repair the heater during the last Unit 2 outage in April and May 2002.

The inspectors reviewed meteorological tower data for Point Beach beginning on September 11, 2002, and determined that prior to elevation of freeze protection issues by site management on October 31, six nights of below freezing temperatures had occurred. In addition, Point Beach had first experienced below freezing temperatures on October 14, and prior to November 1, had experienced approximately 30 hours with below freezing temperatures in the areas immediately surrounding the site. While the beginning of the current winter season had been relatively warm, historical weather data for Two Rivers, Wisconsin, indicated that the average low temperature for October was 29 degrees Fahrenheit (°F) and for November was 16.9°F. Finally, the low temperature extreme recorded for Green Bay, Wisconsin, located approximately 30 miles from Point Beach, was 8°F for October and -12°F for November.

The inspectors determined that not sufficiently coordinating and being adequately prepared for the onset of cold weather prior to November 1, 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 April 29, 2002. 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 power operations, and 2) if left uncorrected, would become a more significant safety concern in subsequent years if the lack of coordination and preparation were to encompass and extend to more safety-related systems.

Using Inspection Manual Chapter 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors answered “no” to the three screening questions in the Phase 1 Screening Worksheet under the Initiating Events column. Based on the answers to the screening questions the inspectors concluded that the issue was a finding of very low safety significance (Green) (FIN 50-266/301/02-13-01). The inspectors determined that no violation of regulatory requirements had occurred since the lack of coordination and preparation for cold weather had not resulted in the actual loss of any safety-related function for the current winter season.

1R04 Equipment Alignment (71111.04)

.1 125-Volts Direct Current (VDC) Complete System Walkdown

a. Inspection Scope

During the week of November 11, 2002, the inspectors performed a complete system walkdown of the Units 1 and 2 125-VDC distribution system to verify proper system configuration. The inspectors used licensee checklists (CLs), wiring diagrams, and operating procedures during the walkdowns to verify that the systems were properly configured for full power operations. The CLs and diagrams were compared against design basis requirements to verify that the documents aligned the 125-VDC systems in accordance with design basis assumptions. The inspectors also performed walkdowns in the control room to verify appropriate switch positions and valve configurations. The inspectors reviewed simulator training for direct current and instrument bus malfunctions. The inspectors reviewed Abnormal Operating Procedure AOP-0.0, "Vital DC System Malfunction," and Emergency Operating Procedure EOP-0, "Reactor Trip or Safety Injection."

The inspectors reviewed Operations Refueling Test Procedure (ORT)-3 to verify that the safety injection (SI) signal that interacted with the 125-VDC system was properly tested. Finally, the inspectors evaluated other elements, such as material condition, housekeeping, and component labeling.

b. Findings

No findings of significance were identified.

.2 120-Volts Alternating Current (VAC) Partial System Walkdown

f. Inspection Scope

During the week of November 11, 2002, the inspectors performed a partial system walkdown of the Units 1 and 2 120-VAC distribution system to verify proper system configuration. The inspectors used licensee wiring diagrams and operating procedures during the walkdowns to verify that the systems were properly configured for full power operations. The diagrams were compared against design basis requirements to verify that the documents aligned the 120-VAC systems in accordance with design basis assumptions. Finally, the inspectors evaluated other elements, such as material condition, housekeeping, and component labeling.

b. Findings

No findings of significance were identified.

.3 1Y01 (Red) 120-VAC Vital Instrument Panel Partial System Walkdown

a. Inspection Scope

During the week of November 25, 2002, the inspectors performed a partial walkdown of the electrical power to the loads on 1Y01 (Red) 120-VAC vital instrument panel to verify proper system configuration. The inspectors followed the electrical power distribution from the feeder buses (D09, D07, and Battery D05); to D01; then to D11 and D26, and through the inverter to 1Y01. The inspectors selected breaker Number 8 (1C127 Loop 'A' Feedwater Rack) and reviewed the loads associated with the breaker. The inspectors interviewed Control Room and Instrument & Control (I&C) Maintenance personnel and conducted walkdowns of the loads supplied from the 1C127 rack.

b. Findings

No findings of significance were identified.

.4 Controller 1-HC-480 Interface with Vital Instrument Panel Partial System Walkdown

a. Inspection Scope

During the week of November 25, 2002, the inspectors walked down the power supplies to 1-HC-480, 'A' feedwater loop bypass valve controller, since the controller appeared, on drawings, to have power supplied from both the 1Y01 and 1Y03 inverters. The inspectors reviewed the controller drawings, the reactor protection rack drawing, and the Manul/Automatic station controller documentation to verify the two power sources in the controller were independent and isolated, one supplying the automatic side and the other to the manual side of the controller. Finally, the inspectors evaluated other elements, such as material condition, housekeeping, and component labeling.

b. Findings

No findings of significance were identified.

.5 Vital Bus Breaker 4160-VAC Control Partial System Walkdown

a. Inspection Scope

During the week of December 2, 2002, the inspectors reviewed the control circuits associated with selected 4160-VAC vital bus breakers to verify proper configuration. Specifically, the inspectors reviewed the control circuit diagram for undervoltage and differential lockout relays. The inspectors reviewed the relationship to a loss of direct current control power to selected breakers and the availability of the breaker to open and allow the diesel generator to load to the bus to determine whether there was sufficient separation such that only one bus would be affected by a loss of any single direct current bus.

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 Zone (FZ) 322, Turbine Building Operating Floor - Unit 1
- FZ-228, Fire Area A19, Battery Room D105
- FZ-226, Fire Area A17, 125-VDC Electrical Equipment Room- D04
- FZ-227, Fire Area A18, 125-VDC Electrical Equipment Room - D03
- FZ-225, Fire Area A16, Battery Room D106
- Fire Zones 334 and 335, Fire Area A32, Computer Room

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, 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.

1R06 Flood Protection Measures (71111.06)

.1 Inspection of Circulating Water System Expansion Joints

a. Inspection Scope

During the week of December 9, 2002, the inspectors performed a walkdown of the main condenser outlet water box expansion joints to evaluate the potential of these joints to contribute to internal flooding. The inspectors also interviewed the cognizant system engineer to understand the inspection frequency and material history of the joints.

b. Findings

No findings of significance were identified.

1R08 Unit 1 Inservice Inspection Activities (71111.08)

a. Inspection Scope

During the U1R27 refueling outage, the inspectors evaluated the implementation of the licensee's inservice inspection program for monitoring degradation of the Unit 1 reactor coolant system (RCS) boundary and the risk significant piping system boundaries based on review of records and in-process observation of non-destructive examinations.

The inspectors reviewed modifications associated with the SI accumulator level transmitter nozzles, disposition of five recordable indications identified during previous nondestructive examinations, a code relief request concerning visual examinations of the EDG, the Unit 1 steam generator condition monitoring assessment for operating Cycles 27 and 28, three American Society of Mechanical Engineers (ASME) Section XI code repairs and replacement activities, and radiographic records for three code welding activities. In addition, the inspectors observed the following nondestructive examinations:

- ultrasonic examination of reactor pressure vessel (RPV) shell to flange weld, RPV-14-683
- ultrasonic examination of letdown from loop 'B' cold leg branch connection to RCS pipe weld, RC-08-DR-1001-01
- ultrasonic examination of 'B' SI accumulator to RCS loop 'B' pipe to valve SI-867B weld, AC-10-SI-1001-19
- ultrasonic examination of SI accumulator T-034A and T-034B Nozzles A/B/C/D
- dye penetrant (PT) examination of regenerative heat exchanger HX-2 welded attachment bottom shell weld, RHE-IWA-1
- remote visual examination of RPV interior surfaces
- direct visual examination of RPV closure head nuts 1 through 16
- direct visual examination of residual heat removal (RHR) to accumulator 'B' line variable spring, SI-2501R-2-SI1.

The records reviewed and activities observed were evaluated for conformance with requirements in the 1998 Edition, with Addenda through 2000, of the ASME Code, Sections III, V, IX, and XI.

The inspectors also reviewed a sample of inservice inspection related problems documented in the licensee's CAP to assess the appropriateness of the corrective actions. Finally, the inspectors reviewed CAP029754, "NDE Data Sheet Had Wrong Instrument Setting," and CAP029756, "Suggested Enhancement to NDE Data Sheet NDE-750.1," which were initiated as a result of this inspection activity.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

.1 Steam Generator Tube Rupture Training Session

a. Inspection Scope

During the week of October 25, 2002, the inspectors observed a simulator requalification training session associated with a steam generator tube rupture scenario. The inspectors observed operations personnel use of 3-way communications, procedure adherence, command and control, and control room decorum to evaluate crew performance. The inspectors discussed simulator feedback and modifications with the simulator software engineer to ensure that the simulator met American National Standards Institute standards for certification. Finally, the inspectors reviewed the critique documentation for the requalification crew.

b. Findings

No findings of significance were identified.

.2 Written Examination and Operating Test Results

a. Inspection Scope

The inspectors reviewed the pass/fail results of individual written tests, operating tests, and simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee during 2002. The number of failures on the written exam was within the acceptable operator license metric.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

.1 Routine Review

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, hardened grease effects on motor-operated valves, 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:

- Service Air during the week of September 30, 2002
- Chemical Volume and Control System during the week of October 13

Finally, the inspectors reviewed CAP029798, "Various Containment Valves Found In Poor Housekeeping Condition," which was initiated as a result of this inspection activity and discussed metal filings on stem threads and packing follower and bolt rust material condition discrepancies.

b. Findings

No findings of significance were identified.

.2 (Closed) Inspection Follow-up Item (IFI) 50-266/98009-03(DRS); 50-301/98009-03(DRS): Containment Hatch Requirement, Maintenance Rule, 10 CFR 50.65. This IFI concerned the effect of repetitive maintenance-preventable functional failures on the containment integrity (CI) maintenance rule functional performance area that had not been considered when determining (a)1 system status (as defined in 10 CFR 50.65). This item was previously discussed in Inspection Report 50-266/98009-03(DRS); 50-301/98009-03(DRS), Section M2.2 and concerned multiple containment airlock door testing failures. The inspectors reviewed CAP 1778, which declared the CI system as an (a)1 system and the performance monitoring plan developed after the system was made (a)1. The inspectors reviewed the corrective maintenance WOs that had been performed on the containment airlock doors and the pressure tests on the doors following maintenance. The maintenance-preventable functional failures had resulted from multiple leakage test failures. The test method was changed from a vacuum test to a pressure test and the doors had been adjusted. The (a)1 monitoring plan had been successfully completed and the CI system returned to an (a)2 status. No violation of requirements occurred.

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:

- September 29, 2002. This work included the Unit 1 refueling outage (U1R27), while Unit 2 remained at full power. This work included preventative maintenance, post-maintenance, and surveillance testing of the P-38B motor-driven auxiliary feedwater (AFW) pump, the Unit 2 P-11A and P-11B component cooling water pumps, and Unit 2 containment isolation valve testing.

- November 3. This work week included EDG ventilation work, safety-related battery charger maintenance, internal inspection of both condensate storage tanks, inspections of AFW pump recirculation line orifices, limited boroscopic inspections of AFW pump suction and discharge lines, and flushes of selected AFW pump SW suction lines.

- November 24. This work week included venting SI piping, work on SI valves, and containment spray pumps.

- December 1. This work week included replacing the P-32D SW Pump, Unit 1 accident fan cooler maintenance and post-maintenance testing (PMT), adjusting the spring pressure on accumulator charging isolation valves, and radiography of AFW piping and components. The week also involved emergent repairs on the primary auxiliary building crane after a control pendant became caught on the spent fuel pool refueling bridge during preparations for dry cask loading.

b. Findings

No findings of significance were identified.

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

.1 Primary Auxiliary Building (PAB) Crane Entanglement With Spent Fuel Pool (SFP) Manipulator Bridge

a. Inspection Scope

On December 5, 2002, the inspectors observed licensee actions as the result of a PAB crane pendant cable entanglement with the SFP manipulator bridge that occurred during preparations for loading dry cask 15. The inspectors evaluated the weight and position of the dry cask hook suspended over spent fuel in the pool and the potential for unwanted crane motion. The inspectors surveyed the crane damage and considered the reliability of the PAB control circuits to determine whether, through unwanted crane motion, the potential for spent fuel damage existed. The inspectors monitored the development, adequacy, and execution of the licensee’s recovery efforts to ensure that actions were taken in a controlled and deliberate manner and did not create the potential for further complications or uncontrolled hook motion. Finally, the inspectors reviewed the adequacy of the licensee’s decision to remove the PAB pendant cable control circuit from service and to resume dry cask loading operations.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Unit 1 Reactor Cavity Foreign Material Evaluation During Refueling Outage

a. Inspection Scope

During the week of October 7, 2002, the inspectors reviewed the licensee's evaluation of foreign material found in the reactor cavity during the Unit 1 outage. Specifically, the inspectors reviewed CAP029732, “U1R27 Upper Cavity FME,” and CA 26645, “Determine Impact on Plant Operation (FM in Core),” to determine the source of the foreign material and whether any material had entered the reactor vessel during refueling operations.

b. Findings

No findings of significance were identified.

.2 Inability of the Unit 1 ‘B’ Steam Generator Blowdown Containment Isolation Valve To Close Against Maximum Differential Pressure

a. Inspection Scope

During the week of October 14, 2002, the inspectors reviewed a vendor calculation that showed that the Unit 1 ‘B’ steam generator blowdown air-operated valve (AOV) isolation valve inside containment, 1MS-5959, may not have been able to shut against steam generator differential pressure when at hot shutdown (1085 pounds per square inch gauge (psig)). The inspectors reviewed the licensee’s conclusion that there was not enough AOV motive force to ensure that the valve would shut as designed during certain design basis events. The inspectors reviewed actions to change valve spring tension and air pressure to place more force on the valve and the licensee’s analytical conclusion that the changes would subsequently allow the valve to shut against maximum differential pressure. Finally, the inspectors reviewed the work package and calculations associated with the AOV adjustment. See 4OA3.2 for more detail and the regulatory disposition of this issue.

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 December 9, 2002, the inspectors reviewed the cumulative effect of OWAs to determine the total impact of these workarounds on plant operations. Specifically, 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 spurious low air pressure alarms during the start of EDGs, direct current under/over voltage alarms received during the start of safeguards equipment, and low flow concerns associated with the AFW pumps to evaluate the operator's ability to respond to nuisance alarms during 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 Traveling Screen ‘Y’ Strainers Ineffective

a. Inspection Scope

During the week of December 9, 2002, the inspectors reviewed OWA 0-02R-006 to verify that the workaround was properly classified and dispositioned in accordance with the criteria of the licensee’s procedure. The workaround concerned the proposed replacement of the traveling screen ‘Y’ strainers due to frequent clogging with lake grass, algae, and other debris, and the additional auxiliary operator burden required to perform cleaning activities. The inspectors also interviewed engineering and operations personnel and compared the licensee’s scheduled OWA response with the acceptable time resolution limits specified in the OWA procedure.

b. Findings

No findings of significance were identified.

.3 Unit 2 Turbine Load Increase After Placing Electro-Hydraulic Control Setting In Hold

a. Inspection Scope

The inspectors reviewed OWA 2-02R-003 to understand the potential effects on plant stability caused by the spurious actuation of turbine generator electro-hydraulic controls, combined with operator response to a plant transient. The workaround concerned preventing the turbine from operating unexpectedly, while placed the electro-hydraulic control setting was in the hold position. The inspectors reviewed the CAP history and associated evaluations to determine the adequacy of licensee actions to address the issue. The inspectors also reviewed the adequacy of posted temporary instructions to ensure that operators had been given appropriate guidance to prevent further main turbine transients. Finally, two subsequent load reductions were reviewed to verify that the spurious actuation of turbine generator electro-hydraulic controls had not been repeated.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 AFW Pump Air-Operated Discharge Control Valve Diaphragm Replacement

a. Inspection Scope

During the week of October 18, 2002, the inspectors reviewed WO 994510 associated with the replacement and testing of a diaphragm for a motor-driven AFW pump discharge control AOV to verify that the PMT was appropriate for the scope of work performed, the pump remained capable of performing the intended safety function, and the pump was restored to an operable condition. The inspectors observed portions of the isolation, maintenance, and repair activities and reviewed the completed WO and PMT documentation.

b. Findings

No findings of significance were identified.

.2 Packing Replacement of ‘A’ Motor-Driven AFW Pump

a. Inspection Scope

During the week of October 21, 2002, the inspectors reviewed Work Package 0205651 associated with P-38A motor-driven AFW pump packing replacement activities to verify that the PMT was appropriate for the scope of work performed, the pump remained capable of performing the intended safety function, and the pump was restored to an operable condition. The inspectors also observed portions of the repacking activities and evaluated packing and lantern ring placement and alignment. The inspectors interviewed the system engineer to understand normal seal package maintenance practices and to determine whether the lantern ring had been correctly placed. The inspectors also observed the PMT run and reviewed the completed documentation to evaluate pump performance.

b. Findings

The initial pump PMT run was not completed because the recirculation flow was 65 gallons per minute (gpm) instead of the expected 75 gpm. The licensee subsequently removed the recirculation line flow orifice and discovered that 24 of the

52 holes in the outer orifice ring contained foreign material. The inspectors examined the orifice after the material had been removed. The orifice was subsequently cleaned and re-installed, and the PMT was repeated. The flow was 75 gpm. Subsequently, the inspectors observed the test run of the other AFW pumps conducted to verify recirculation flow was within specification. More information is provided in Section 4OA3.5.

.3 AFW Pump Suction Drain Valve Replacement

a. Inspection Scope

During the week of October 21, 2002, the inspectors reviewed WO 9949098, associated with the replacement and testing of a P-38A motor-driven AFW pump suction drain valve, AF-0038, to verify that the PMT was appropriate for the scope of work performed and to ensure that the valve remained capable of maintaining suction line integrity. The inspectors observed portions of the isolation, maintenance, and replacement activities and reviewed the completed WO and PMT documentation to ensure the system had been returned to an operable status.

b. Findings

No findings of significance were identified.

.4 Unit 1 'A' Containment Spray Pump Oil Change

a. Inspection Scope

During the week of November 11, 2002, the inspectors observed PMT activities associated with WO 0200854, "Change Oil in 1P-14A Containment Spray Pump," and Inservice Test (IT) 05, "Containment Spray Pumps and Valves (Quarterly) Unit 1," to verify that the PMT was appropriate for the scope of work performed, the pump remained capable of performing the intended safety function, and the pump was restored to an operable condition. The inspectors reviewed the completed test and WO documentation to verify that the test data were complete, appropriately verified, and met the requirements of the test procedure.

b. Findings

No findings of significance were identified.

.5 Unit 1 'B' Containment Spray Pump Oil Change

a. Inspection Scope

During the week of November 11, 2002, the inspectors observed PMT activities associated with WO 0200855, "Change Oil in 1P-14B Containment Spray Pump," and IT-05, "Containment Spray Pumps and Valves (Quarterly) Unit 1," to verify that the PMT was appropriate for the scope of work performed, the pump remained capable of performing the intended safety function, and the pump was restored to an operable condition. The inspectors reviewed the completed test and WO documentation to verify that the test data were complete, appropriately verified, and met the requirements of the test procedure.

b. Findings

No findings of significance were identified.

.6 Unit 2 RHR Containment Sump Suction Valve 2SI-850B

a. Inspection Scope

During the week of December 2, 2002, the inspectors reviewed WO 0216212, "P-10B RHR Pump Sump 'B' Suction Valve Operator," associated with repacking and repairing an oil leak on valve 2SI-850B to verify that the PMT was appropriate for the scope of work performed, the valve remained capable of performing the intended containment isolation and recirculation safety functions, and the valve was restored to an operable condition. The inspectors also interviewed engineering personnel and reviewed an engineering justification to ensure that the new parts, different from those originally installed, were capable of performing the intended safety and design functions. Finally, the inspectors reviewed CAP030366, "Two Questions on Form PBF 1608 Were Not Check Marked For Calculation 2001-001," which was initiated as a result of this inspection activity and discussed attention-to-detail errors associated with a document calculation form.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

.1 Review of Selected U1R27 Activities

a. Inspection Scope

The inspectors observed work activities associated with U1R27, which began during the last inspection period and ended on October 17, 2002. The inspectors assessed the adequacy of outage-related activities, including configuration management, clearances and tagouts, and RCS reduced inventory operations. Additionally, the inspectors reviewed refueling operations for implementation of risk management, preparation of contingency plans for loss of key safety functions, conformance to approved site procedures, and compliance with Technical Specifications (TSs). The inspectors also verified compliance with commitments made in the licensee's response to Generic Letter 88-17, "Loss of Decay Heat Removal." The following major activities were observed or performed:

- outage planning meetings
- draining the RCS in preparation for reactor vessel head set

- adequate reactor vessel level and temperature instrumentation during periods of reduced inventory
- reactivity monitoring of shutdown plant conditions including establishment of source range nuclear instrument channel check criteria
- review of boron concentration sampling results, source range nuclear instrumentation system operability, containment closure capability, and refueling cavity water levels during head lift and mode transition activities
- walkdowns of RHR systems during reduced inventory to verify decay heat removal capabilities
- walkdowns of selected shutdown inventory addition makeup paths
- walkdowns of RCS boundary integrity prior to increasing reactor vessel inventory levels
- walkdowns to verify that all debris which could inhibit mitigating the effects of a design basis accident were removed from containment
- other general outage activities, including foreign material exclusion controls and safety shutdown assessments
- heat-up observations to normal operating temperatures and pressures, including selective reviews of mode transition checklists
- a review of the core reload safety evaluation, initial criticality, and low power physics testing data.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Mis-Calibration of Unit 1 Steam Generator Level Setpoint Programmer Module

a. Inspection Scope

During the week of October 21, 2002, the inspectors reviewed the results of the calibration of the Unit 1 steam generator level setpoint programmer modules. These calibrations had been conducted around the last week of September; however, on October 18, reactor operators observed that as reactor power was increasing from 28 percent to 40 percent, steam generator level increased above the normal limit of 64 percent. Operators entered AOP-2B, “Feedwater System Malfunction,” Revision 10; put the level control system in manual; and were able to stop steam generator level increase at 75 percent, below the 78 percent limit at which feedwater flow to both steam generators would have been isolated and at which a transient could have been initiated. The licensee’s initial review of this self-revealing problem identified that the I&C technician who calibrated proportional controller LM-463F on September 23 had inadvertently not restored a dial setting after adjusting two potentiometers as part of the calibration. Restoration of the setting was specified in the procedure.

b. Findings

The inspectors identified a finding of very low safety significance (Green) concerning the failure of a technician to properly calibrate feedwater controller LM-463F.

Description

Around the last week of September, I&C technicians had calibrated numerous instruments in the Unit 1 feedwater control system as specified by Unit 1 I&C Procedure, 1ICP 05.022, “Feedwater Control,” Revision 20. On September 23, one of those technicians calibrated proportional control LM-463F, which was normally calibrated to provide a control signal to maintain level in both steam generators at 60 percent. The setting was below the 64 percent that controller LM-463D was set to maintain and the level at which the generators were maintained. The LM-463F provided backup level control in the event of failure of LM-463D.

The seven steps to calibrate LM-463F were specified in Data Sheet 1 of the procedure. The technician who performed the calibration had performed it in the past without a problem, but, apparently because of inattention to detail, did not restore a dial setting after taking three as-found readings, adjusting two potentiometers, and taking three as-left readings. The error was not identified during I&C supervisory review of the data sheet and did not manifest itself because of the level system design and the nature of the error, until reactor operators resumed power escalation from a chemistry and flux map hold at 28 percent.

Analysis

The inspectors determined that the error in calibrating the steam generator level system controller, an error that affected both generators, was of more than minor significance in that it was associated with the human performance attribute of the initiating events cornerstone and affected the cornerstone objective of limiting the likelihood of those events (such as a loss of feedwater) that upset plant stability. The inspectors used Manual Chapter 0609, Significance Determination Process, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” regarding initiating events and determined that the finding did not contribute to the likelihood of a primary or secondary system loss-of-coolant accident initiator, did not contribute to the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available, and did not increase the likelihood of a fire or internal/external flood. Therefore, the finding screened as Green, a finding of very low safety significance.

Enforcement

In that the steam generator level control system did not provide a safety-related function, no regulatory violation was identified for the failure of the I&C technician to follow the calibration procedure; however, the failure was considered a finding (FIN 50-266/02-013-02). The error in calibration was entered in the licensee’s CAP as CAP029864, Steam Generator Water Level Excursion Due to Improperly Set Program Module.

.2 Cold-Start of Unit 1 Turbine-Driven AFW Pump

a. Inspection Scope

During the week of October 14, 2002, the inspectors observed performance of Procedure IT 08A, "Cold Start of Turbine-Driven Auxiliary Feed Pump and Valve Test (Quarterly) Unit 1," Revision 29, from the main control room to verify system operability. The inspectors reviewed the test procedure to evaluate the possibility of preconditioning the turbine-driven AFW discharge valves by stroking them closed and testing the open direction prior to performing the test in the closed position. The inspectors also reviewed AFW design basis documentation to ensure the test met design requirements. Finally, the inspectors reviewed CAP029842, "IT8A/9A," which was initiated as a result of this inspection activity and discussed procedure enhancements to minimize valve manipulations prior to recording ASME inservice testing data.

b. Findings

No findings of significance were identified.

.3 Unit 1 AFW and Anticipated Transient Without Scram Mitigation System Actuation Circuitry (AMSAC) Testing

a. Inspection Scope

During the week of October 12, 2002, the inspectors observed AFW pump and AMSAC actuation testing performed in accordance with ORT-3C, "Auxiliary Feedwater System and AMSAC Actuation - Unit 1," Revision 4, to determine the ability of AFW and AMSAC systems to meet design basis requirements. The inspectors observed the pre-job brief, reviewed compliance with the procedure prerequisites, observed communications, verified completion of all applicable procedure steps, observed shift turnover during testing, and ensured verification of test results prior to returning the equipment to service. Finally, the inspectors verified that the operations refueling test met TS surveillance requirements and tested the applicable portions of AMSAC AFW actuation circuitry.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

.1 SI Accumulator Temporary Relief Valve

a. Inspection Scope

During the week of October 14, 2002, the inspectors reviewed Unit 1 Temporary Modification 02-044, "Installation of a Temporary Relief Valve for SI-830B, T-34B SI Accumulator Relief," to verify that the modification was properly installed and had no effect on the operability of the safety-related equipment. The inspectors selected the SI accumulator to ensure that operability of the risk significant SI accumulator would be maintained when the licensee gagged shut the installed relief valve, SI-830B, to eliminate a nitrogen leak. The inspectors reviewed the proposed temporary modification to ensure the new relief valve would meet all design requirements and that it would not cause deleterious effects on the accumulator water level instrumentation and Engineering Calculation 2002-0034, "Special Calculation for Evaluating Upstream Flow Restrictions for SI Accumulator Relief Valve Temporary Modification." The inspectors also reviewed Engineering Calculation 2002-0036, "Potential for Aspiration of Boric Acid Solution by Lifting of Temporary Relief Valve," performed to address an inspector identified concern with possible aspiration of the accumulator fluid through the level monitoring piping if the temporary relief valve lifted.

b. <u>Findings</u>

No findings of significance were identified.

.2 <u>Component Cooling Water 'C' Heat Exchanger SW Blow-Down Leak Temporary Repair</u>

a. <u>Inspection Scope</u>

During the week of December 9, 2002, the inspectors reviewed Temporary Modification TM 02-040, "Temporary Repair of CC [Component Cooling] HX-12C SW Blow-Down Leak," to verify that the modification was properly installed and had no effect on the operability of safety-related equipment. The inspectors also reviewed the immediate actions taken, CAP029327 (Through-Wall Leakage, HX 12C SW Blow-Down Line), and the plans to install the permanent replacement piping. The inspectors performed a visual inspection of the replacement piping and adjoining weld to verify that the temporary modification was performing the intended function.

b. <u>Findings</u>

No findings of significance were identified.

Emergency Preparedness

EP6 <u>Drill Evaluation</u> (71114.06)

.1 <u>Steam Generator Tube Rupture Requalification Training Scenario</u>

a. <u>Inspection Scope</u>

During the week of October 21, 2002, the inspectors observed an operations personnel requalification training crew perform classifications and notifications for a steam generator tube rupture scenario. The inspectors observed the time from the identification of the emergency action level until security personnel were told to perform notifications to evaluate whether the emergency planning goal of 15 minutes had been met. The inspectors reviewed simulator evaluation instructor plans to time other operations requalification crews during this training cycle to determine whether the 15 minute goal could consistently be met amongst operating crews.

b. Findings

No findings of significance were identified.

.2 Resident Inspector Observation of Emergency Preparedness Drill

a. Inspection Scope

On November 7, 2002, the resident inspectors observed an emergency preparedness drill to evaluate the adequacy of drill conduct and critique performance. The inspectors observed the drill from the control room (simulator), technical support center, and operations support center to evaluate emergency preparedness performance at multiple locations. The inspectors also attended the control room and technical support center critique sessions immediately following the drill termination on November 7, to evaluate the licensee's ability to identify emergency planning weaknesses and deficiencies.

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, Radiation Work Permit (RWP) Reviews, and Observations of Radiation Worker Performance

a. Inspection Scope

The inspectors conducted walkdowns of the radiologically controlled area to verify the adequacy of radiological boundaries, postings, and locking devices. Specifically, the inspectors walked down several radiologically significant work area boundaries (high radiation areas [HRAs], HRAs with radiation levels greater than 1,000 millirem/hour (mrem/hr), and a very high radiation area [VHRA] with potential radiation levels > 500 rads/hour) in the Unit 1 containment, auxiliary building, radioactive waste, and spent fuel pool areas. Confirmatory radiation measurements were taken to verify that these areas and other selected areas were properly posted and controlled in accordance with 10 CFR Part 20, licensee procedures, and TSs. The inspectors reviewed RWPs (for routine plant tours, reactor head penetration testing/repairs, and an entry into the Unit 1 reactor "keyway") for engineering, operations, and maintenance activities, in support of U1R27. The RWPs were evaluated for protective clothing requirements, respiratory protection concerns, electronic dosimetry alarm setpoints, and radiation protection hold points, and to verify that work instructions and controls had been adequately specified and that electronic dosimeter set points were in conformity with survey indications. The inspectors also observed radiation workers performing the activities described in Section 2OS2.3, to evaluate their awareness of radiological work conditions, and to verify the implementation of radiological controls specified in applicable RWPs.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed self-assessments, Nuclear Quality Assurance audits, and licensee ARs, written since the last assessment, which focused on access control to radiologically significant areas. Additionally, the inspectors specifically reviewed ARs initiated in conjunction with U1R27, which focused on access control to radiologically significant areas, radiation worker practices, and radiation protection technician work practices. The inspectors reviewed these documents to assess the licensee's ability to identify repetitive problems, contributing causes, the extent of conditions, and implement corrective actions to achieve lasting results.

b. Findings

No findings of significance were identified.

2OS2 As-Low-As-Is-Reasonably-Achievable (ALARA) Planning and Controls (71121.02)

.1 Radiological Work/ALARA Planning

a. Inspection Scope

The inspectors examined the station's procedures for radiological work/ALARA planning and scheduling, and evaluated the dose projection methodologies and practices implemented for the U1R27, to verify that sound technical bases for outage dose estimates existed. The inspectors reviewed the station's collective exposure histories from 1976 to the present, current exposure trends from ongoing plant operations, and completed radiological work activities for U1R27 to assess current performance and outage exposure challenges. The inspectors evaluated the licensee's effectiveness in exposure tracking for the outage to verify that the licensee could identify problems with its collective exposure and take actions to address them. Additionally, the inspectors reviewed five radiologically significant RWP/ALARA planning packages to verify that adequate person-hour estimates, job history files, lessons-learned, and industry experiences were utilized in the ALARA planning process. As part of the reviews of the planning packages, the inspectors reviewed Total Effective Dose Equivalent (TEDE) ALARA evaluations developed for upper/lower reactor cavity decontamination, reactor head underneath work, upper reactor internals lift rig inspection, and cavity seal ring demolition. The inspectors examined the TEDE ALARA evaluations to assess the licensee's analysis for the potential use of respiratory protection equipment and to verify the adequacy of the licensee's internal dose assessment processes/program for the aforementioned work evolutions.

b. Findings

No findings of significance were identified.

.2 Verification of Exposure Goals and Exposure Tracking System

a. Inspection Scope

The inspectors reviewed the licensee’s methodology and assumptions used to develop outage exposure estimates and exposure goals for U1R27. Pre-job ALARA reviews (as well as some post-job reviews) were examined to evaluate the licensee’s ability to assess actual outage doses, as well as the overall effectiveness of the work planning. The inspectors compared exposure estimates, exposure goals, job dose rates, and person-hour estimates for consistency to verify that the licensee could project, and thus better control radiation exposure. The inspectors examined job dose history files and dose reductions anticipated through the licensee’s implementation of lessons-learned to verify that the licensee could accurately forecast outage doses. The inspectors examined the actual U1R27 radiation dose exposure data, to date, of 68.5 person-rem (the projected dose was 67.27 person-rem) and the original 75 person-rem outage goal. The inspectors then reviewed the revised outage dose goal of 90 person-rem to assess the impact of outage emergent work encountered, which was mostly work on the reactor head. The inspectors also reviewed the licensee’s exposure tracking system to verify that the exposure tracking detail, exposure report timeliness, and exposure report distribution were sufficient to support control of collective exposures. Additionally, the inspectors reviewed dose tracking records for all workers on selected projects, to assess the licensee’s effectiveness in maintaining individual exposures ALARA and minimizing significant dose variations across the workgroups.

b. Findings

No findings of significance were identified.

.3 Job Site Inspections, Radiation Worker Performance, and ALARA Controls

a. Inspection Scope

The inspectors observed work activities performed in radiation areas, HRAs, and locked HRAs to evaluate the use of ALARA controls. Specifically, the inspectors reviewed the adequacy of RWPs, radiological surveys, attended pre-job radiological briefings, and assessed job site ALARA controls, in part, for the following Unit 1 work activities:

- ultrasonic testing (UT) of reactor head penetrations;
- reactor “keyway” area entry, for in-core instrumentation snubber refurbishment; and
- fit-up and welding preparations on reactor head thermal sleeve 1.

The inspectors examined worker instruction requirements, which included protective clothing, engineering controls to minimize dose exposures, the use of predetermined low dose waiting areas, as well as the on-the-job supervision by the work crew leaders to verify that the licensee had maintained the radiological exposure for these work activities ALARA. The inspectors evaluated radiation protection technician performance for each of the aforementioned work evolutions, as well as observing and questioning workers at each job location to determine that they had adequate knowledge of radiological work conditions and exposure controls. Enhanced job controls including radiation protection technician use of electronic teledosimetry and remotely monitored cameras were also evaluated to assess the licensee’s ability to maintain real time doses ALARA in the field. Additionally, the inspectors evaluated the licensee’s radiation protection personnel implementation of dosimetry placement changes necessitated by significant dose rate gradients during Unit 1 reactor head work testing/repairs.

b. Findings

No findings of significance were identified.

.4 Source Term Reduction and Control

a. Inspection Scope

The inspectors reviewed and discussed the status of the station’s source term reduction program in order to verify that the licensee had an effective program in place, was knowledgeable of plant source term reduction opportunities, and that efforts were being taken to address them. Work control mechanisms for U1R27 were evaluated to ensure that source term reduction plans had been appropriately implemented. The inspectors reviewed source term reduction initiatives completed for the outage, such as supplementary water processing, flushing, and prioritizing/sequencing of installation of temporary shielding packages and complex scaffolding arrangements, to minimize exposure. The inspectors also reviewed the overall source term reduction plan, which included improved tracking/mitigation of hot spots, use of submicron filtration, tracking/trending of online/shutdown chemistry initiatives, and cobalt reduction initiatives through stellite control. The inspectors reviewed the licensee's continuing source term reduction techniques to verify that source term control strategies were ongoing and future initiatives were being explored.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors examined the licensee’s lessons-learned from the U2R25 dose goal estimation process and its subsequent effect on the establishment of the U1R27 dose goal. The inspectors reviewed an Emergent Assessment for the U1R27 which was conducted by the nuclear oversight department (quality assurance). The inspectors examined in-progress ALARA reviews for the 2CV-296 refurbishment and the modification/replacement of the ‘C’ accident fan coolers. Additionally, the inspectors evaluated selected outage-generated ARs, which focused on ALARA planning and controls. The inspectors evaluated the effectiveness of the licensee’s self-assessment process to identify, characterize, and prioritize problems. Additionally, the inspectors assessed the licensee’s ability to identify repetitive problems and to determine contributing causes, extent of conditions, and corrective actions which would achieve lasting results.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP3 Response to Contingency Events (71130.03)

a. Inspection Scope

The Office of Homeland Security developed a Homeland Security Advisory System to disseminate information regarding the risk of terrorist attacks. The Homeland Security Advisory System implements five color-coded threat conditions with a description of corresponding actions at each level. The NRC Regulatory Information Summary 2002-12a, dated August 19, 2002, "NRC Threat Advisory and Protective Measures System," discusses the Homeland Security Advisory System and provides additional information on protective measures to licensees.

On September 10, the NRC issued a Safeguards Advisory to reactor licensees to implement the protective measures described in Regulatory Information Summary 2002-12a in response to the Federal government declaration of threat level "orange." Subsequently, on September 24, the Office of Homeland Security downgraded the national security threat condition to "yellow" and a corresponding reduction in the risk of a terrorist threat.

The inspectors interviewed licensee personnel and security staff, observed the conduct of security operations, and assessed licensee implementation of the threat level "orange" protective measures. Inspection results were communicated to the region and headquarters security staff for further evaluation.

b. Findings

No findings of significance were identified.

3PP4 Security Plan Changes (71130.04)

a. Inspection Scope

The inspectors reviewed Revisions 1 and 2 to the Point Beach Security Safeguards and Contingency Plan, and Revisions 1 and 2 to the Point Beach Security Training and Qualifying Plan to verify that the changes did not decrease the effectiveness of the Plans. The referenced revisions were submitted in accordance with 10 CFR 50.54(p) by licensee's letters dated August 1, 2002, and October 8, 2002.

b. Findings

No findings of significance were identified

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

.1 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee's determination of PIs for the occupational radiation safety cornerstone (Occupational Exposure Control Effectiveness) to verify that the licensee accurately determined this PI and had identified all occurrences required by the indicator. The accuracy and completeness of the data was assessed against the criteria specified in Nuclear Energy Institute 99-02, Revision 2, "Regulatory Assessment Performance Indicator Guideline." Specifically, the inspectors reviewed the licensee's NRC Occupational Exposure Performance Indicator Data quarterly/monthly reports for the 3rd quarter of 2001 through August 2002, as well as ARs for 2001 and 2002, to ensure that there were no PI occurrences that were not identified by the licensee. The inspectors 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 were adequate. Additionally, during plant walkdowns (Section 2OS1.1), the inspectors assessed the adequacy of posting and controls of HRAs with radiation levels greater than 1,000 mrem/hr, which contributed to the Occupational Exposure Control Effectiveness PI.

b. Findings

No findings of significance were identified.

.2 Emergency Alternating Current System Power Availability

a. Inspection Scope

During the week of December 16, 2002, the inspectors reviewed reported data for the 4th quarter of 2001 through the 1^{st}, 2^{nd}, and 3^{rd} quarters of 2002 for the Emergency

Alternating Current System Power Availability PI for Units 1 and 2 using the definitions and guidance contained in NEI 99-02. The inspectors reviewed station log entries and system engineer data sheets for periods of system unavailability to verify that planned and unplanned unavailability hours were characterized correctly in determining PI results. The inspectors also performed independent calculations to verify PI data and reviewed the NRC response to Frequently Asked Question 318, comparing the response to the actions taken by the licensee. Finally, the inspectors reviewed selected surveillance test procedures associated with the EDGs to verify that the surveillance tests did not render the generators unavailable for performing their safety-related function.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Inadequate and Untimely Corrective Actions Relating to Flooding of Manholes Containing Safety and Non-Safety Related Cables

a. Inspection Scope

The inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action system at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Minor issues entered into the corrective action system as a result of inspectors' observations are generally denoted in the report. During the week of December 9, 2002, the inspectors reviewed corrective actions associated with flooded manholes containing electrical cables.

b. Findings

One finding of very low risk significance (Green) was identified by the inspectors for the licensee's failure to establish timely and adequate corrective actions to address the flooding of manholes which contain both safety and non-safety related systems, structures, and components. The inspectors identified that the licensee had not implemented effective corrective actions to address long-standing problems with flooding in manholes and had deferred the implementation of corrective actions with insufficient basis.

As part of the Selected Issue Follow-up Inspection of Inspection Procedure 71152, the inspectors selected CAP029059, Medium Voltage Cables in Duct Packs in Flooding Water and Manholes Flooded, for review (dated August 16, 2002). This CAP documented that Manholes 5 and 9 contained water, although the water level was below the cables contained therein. Apparent Cause Evaluation 000866, Medium Voltage Cables in Duct Packs in Flowing Water and Manholes Flooded, documented the evaluation and resolution of this issue and was completed on September 30, 2002. The evaluation determined that the manholes were flooded due to a planned manhole inspection WO being inappropriately deferred when it was due to be performed in June 2002. The activity was deferred for three months due to Unit 2 being in a refueling outage. The WO activity was subsequently performed by inspecting the manholes and pumping out any water. The inspectors concluded that the corrective actions associated with this issue were appropriate.

Also, CAP029059 documented that the flooding of manholes was a repeat issue. Condition Evaluation (CE) 010547, Medium Voltage Cables in Duct Packs in Flowing Water and Manholes Flooded, was also referenced as the document which evaluated the flooding effects on installed cables. The CE provided a summary of various issues relating to submerged cables and flooding in manholes and noted that some cables were to be replaced and some submerged cables tested to determine if the scope of cables tested should be expanded. This activity is currently scheduled for April 2004 during the U1R28 refueling outage. The CE also documented that other CAPs existed to address long-standing problem of flooding in manholes due to ground water intrusion. Other CAPs had also been opened to track the winter problem of ice formation in the facades (the buildings that enclose the Point Beach containments), due to water dripping from conduits entering the facades from Manholes 3 and 4. For example, CAP023677, "Massive Formation of Ice Has Collected on Cable Tray in Southwest Corner of Unit 1," documented an approximate 500 pound ice formation on a cable tray and presented industrial-safety concerns and exceedance of cable tray design loads. This CAP was written in March 1997.

The inspectors noted that since 1997, approximately 15 CAPs have been written relating to flooded manholes, submerged cables in manholes, ice formation due to flooded manholes, effects of water on cables, and spurious alarms relating to manholes. Based on the number of CAPs and associated ineffective corrective actions, the inspectors concluded that the licensee had not implemented effective corrective actions to address the problem of cables flooded in manholes. This is further discussed in the report sections below.

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed numerous documents relating to flooding of manholes and associated CEs and corrective actions. The inspectors' review included verification that problem identification was complete, accurate, timely, and the consideration of extent of condition, generic implications, common cause, and previous occurrences were adequate.

(2) Issues

The inspectors identified that the licensee was effective in identifying and documenting numerous instances of manholes being flooded. In one instance, a cable failure was directly attributed to the effects of being exposed to wet environments and submergence.

The inspectors noted that the majority of these documents referred to, and relied upon, existing corrective actions such as the implementing a WO to periodically inspect manholes and pump out any flooded manholes. However, these documents did not address how these conditions continued to exist even with the manhole inspections being performed. Although subsoil water intrusion was recognized as a contributing factor, flooded manholes continued to exist even after a new subsoil pump was installed. The documents and corrective actions did not address the need to potentially increase the manhole inspection frequency to further preclude or limit cable submergence.

b. <u>Implementation and Effectiveness of Corrective Actions</u>

(1) <u>Inspection Scope</u>

The inspectors reviewed various corrective action documents to evaluate the licensee's evaluation and disposition of performance issues, implementation of corrective actions, and application of risk insights for prioritization of issues and corrective actions.

(2) <u>Issues</u>

- The number of repeat condition reports and CAPs regarding flooding in manholes did not result in a re-evaluation of the adequacy of the established manhole inspection frequency. This weakness was particularly evident based on the results of an NRC inspection of selected manholes on December 12. The inspectors requested licensee personnel to provide visual access to Manholes 5, 9, 18, and 19. The inspectors found that Manhole 5 was virtually empty, Manhole 9 had approximately 2 feet of water; Manhole 18 contained approximately 4-5 feet of water, and Manhole 19 had approximately 6-8 feet of water. The cables, cable trays, and supports in Manhole 19 were submerged. Visual inspection of cable trays and associated supports could not be performed at the time of this inspection due to the area being classified as a confined space. Of concern were the potential for corrosion of cable trays or supports, deterioration of cable jacket or copper shielding, and the impact on any existing cable splices.

  The inspectors further reviewed WO 0208738 used to perform the manhole inspections and noted that the inspection of manholes is only performed between March and October. The inspectors concluded that the maintenance activity frequency was inadequate based on the identified water in manholes. Additionally, the WO only required the inspection of Manholes 1-21 and 'B.' The inspector could not ascertain why other manholes, such as Manhole 'A', were not also inspected for water intrusion.

- The various CAPs did not address the long-term effects of cable submergence but rather referred to other similar CAPs which documented flooded manholes and submerged cables. A number of CAPs stated that cables in submerged condition is a long-term degradation issue and does not provide an operability challenge. The inspectors pointed out that since the facilities has been operating for over 25 years, the concern for long-term cable degradation issue may be applicable today.

- Root Cause Evaluation (RCE) 97-096, “Circulating Water Pump Power Cables,” February 1998, was performed to evaluate the cause of severe outer jacket degradation and minor indentation to the ground shield and inner-insulation of the circulating water pump power cable. Megger testing of this cable revealed the ‘C’ phase conductor and the ‘A’ & ‘C’ phase shields were grounded. The scope of the RCE was to find the cause of the cable degradation. The cause of the cable failure was determined to consist of:

  - cable insulation failed by loss of electrical properties due to water absorption
  - deterioration of cable jacket is a long-term degradation issue
  - water chemistry promotes corrosion on the copper tape shield
  - loss of jacket and copper shield could promote failure of cables

  The RCE recommended/identified six corrective actions and one short-term action. The inspectors verified the short-term action of periodically inspecting and pumping water from manholes was being performed, albeit concerns were identified as discussed earlier in this report section. One other corrective action was for site engineering to establish a cable monitoring and testing program to monitor and/or replace cables as required. This latter corrective action was entered into the licensee’s CAP and tracked by CE007761. In December 1998, this action was closed based on an operating experience report, Safety Evaluation Report 97-06, “Aging of PVC-Insulated Instrumentation and Control Cables,” tracking the same recommendation of establishing a cable monitoring program, although for a different technical issue. The inspectors noted that the safety evaluation report was also closed in December 1998. The safety evaluation report closeout stated that the recommendation to establish a cable monitoring program was not warranted due to the low frequency of cable degradation issues. However, the inspectors concluded that there was insufficient technical basis to not implement the RCE recommended corrective actions. Specifically, the basis for the closure did not address the issues raised in RCE 97-96, did not document the condition of cables in manholes given their periodic submergence, and did not address the effect of cable submergence on any installed cables splices, or cable trays and associated supports. Furthermore, the inspectors concluded that the scope of review for the safety evaluation report cable issue was different than that for the RCE cable submergence issue. Hence, while it may be appropriate to not establish a cable monitoring program for aging issues relating to PVC-insulated cables, that same justification was not appropriate for addressing the cable submergence and failure issues.

- The inspectors did note that some cables will be replaced in U1R28 refueling outage and testing will be performed to ascertain their condition. However, this testing scope was limited and alone would not address the issues of other submerged cables, submerged cable splices, and existing physical condition of splices and cable trays or supports.

Analysis and Enforcement

In summary, the licensee's corrective actions relating to cables submerged in manholes has been inadequate. The licensee has not performed any physical inspection of cables, cable splices, cable trays, cable tray supports, identified those cables susceptible to cable degradation in submerged environments, prioritized inspection or testing of cables, nor considered potential risk to the plant system, structures, and components based on a potential cable failure due to periodic submergence and long-term effects of same.

The inspectors considered this issue to be greater than minor based on an evaluation that, if left uncorrected, it would become a more significant concern since the lack of effective corrective actions to inspect and pump out water in manholes could affect safety-related cables routed through manholes, such as those for SW pumps. Additionally, some of these cables routed in manholes provide power to safety-related buses from the licensee's offsite power systems. Hence the loss of such power, due to cable failures, could result in momentary loss of power to the bus and the inability to re-energize the affected buses from the normal power source. Since the identified water intrusion conditions had not caused any safety-related equipment failures at this time, the inspectors concluded that the manhole conditions did not represent a condition adverse to quality and the issue did not constitute a violation of regulatory requirements.

This issue was categorized as a finding of very low risk significance (Green) by the inspectors for the licensee's failure to establish timely and adequate corrective actions to address the flooding of manholes which contain both safety and non-safety related systems, structures, and components (FIN 50-266/301/02-13-03). The inspectors identified that the licensee had not implemented effective corrective actions to address long-standing problems with flooding in manholes and had deferred the implementation of corrective actions with insufficient basis.

The inspectors also observed that the flooded manholes were identified by the inspectors on December 12. However, CAP 30419, written on December 13. did not describe the as-found condition of the flooded manholes. It solely documented the questions by inspectors regarding the frequency of the manhole pumping and the number of manholes inspected. The CAP problem description and subsequent screening reviews were therefore considered inadequate. On December 17, the licensee initiated actions to evaluate pumping out the manholes throughout the year and to evaluate the need to inspect other manholes for similar conditions.

.2 High-Energy Line Break Issue for Primary Auxiliary Building From 1997

a. Inspection Scope

During the week of October 21, 2002, the inspectors reviewed RCE 000051, "Untimely Corrective Action - Failure to Establish Qualification Files for Equipment," dated June 13, 2002. The RCE was conducted to determine why it had taken over 4 years to resolve an outstanding operable but nonconforming issue related to the 1997 conclusion that certain equipment on the 26' elevation and below of the primary auxiliary building was not included in the environmental qualification/high energy line break program. In addition to RCE 000051, the inspectors reviewed administrative procedures, other CAP documents, and interviewed plant personnel.

b. Findings

The RCE appropriately concluded that the delay in resolving the high-energy line break issue was caused by a weakness primarily in the area of program management. Factoring into this were budget and workforce limitations, and staff-level and engineering management turnover. In the past several years, these factors have affected the resolution of several issues at Point Beach.

The extent of condition evaluation conducted and the corrective actions proposed as part of the RCE were also appropriate. Final resolution of the specific high-energy line break issue is scheduled for mid-2003.

4OA3 Event Follow-up (71153)

.1 (Closed) Unresolved Item (URI) 50-301/02-10-05 and Licensee Event Reports (LERs) 301/2002-002-00 and 301/2002-002-01: Pressurizer safety valve failed to lift at test pressure.

Finding

The inspectors identified a finding of very low safety significance (Green) concerning the operation of Unit 2 from December 2000 to April 2002 with one inoperable pressurizer safety valve. The finding represented a failure to operate Unit 2 in accordance with TSs which required that two pressurizer safety valves be operable with lift settings $\geq$2410 psig and $\leq$2560 psig in Modes 1, 2, and 3, and portions of Mode 4. A Non-Cited Violation (NCV) of TS requirement 3.4.10, "RCS Pressurizer Safety Valves," was identified.

Description

Licensee Event Report 301/2002-002-00 and URI 50-301/02-10-05 were previously discussed in NRC integrated Inspection Report 50-266/02-10; 50-301/02-10, Section 4OA3.1. Since an analysis was required to determine the risk significance of the finding and the licensee's ability to have met licensing basis, design basis, and the Anticipated-Transient-Without-Scram (ATWS) rule requirements, the issue was designated a URI pending regulatory review of the licensee's and nuclear steam supply system vendor's containment and RCS pressure response analysis.

Analysis

The inspectors reviewed LER supplement 301/2002-002-01, vendor Letter WEP-02-56, “ATWS Unfavorable Exposure Times,” and licensee Calculation 2002-0030, “Change in Core Damage Risk Associated with an Inoperable Primary Safety Valve,” to evaluate the risk impact of having operated Unit 2 with one inoperable pressurizer safety valve for an entire operating cycle. The inspectors determined that the licensee’s conclusion that the change in core damage frequency as a result of the inoperable safety valve was equal to 2.1E-7/year was accurate. In addition, regional and Office of Nuclear Reactor Regulation Senior Risk Analysts found this value to be accurate. Since the change in core damage frequency was determined to be less than 1E-6, the issue of having operated Unit 2 with one inoperable pressurizer safety valve for an entire operating cycle was determined to be of very low risk significance (Green).

Enforcement

Technical Specification Section 3.4.10, “RCS Pressurizer Safety Valves,” requires that two pressurizer safety valves be operable with lift settings $\geq$2410 psig and $\leq$2560 psig in Modes 1, 2, and 3, and portions of Mode 4. Contrary to the above, Unit 2 operated in Mode 1 from December 2000 to April 2002 with a safety valve (2RC-435) that would not have lifted at the required setting. Since this violation was determined to be of very low risk significance (Green) and because the licensee entered the finding into its CAP, the violation was treated as a Non-Cited Violation (NCV 50-301/02-13-04) consistent with Section VI.A. of the NRC Enforcement Policy. This violation was entered into the licensee's corrective action system as CAP003109, “RC-435 Failure to Lift, Cause, Reference CAP 003020.”

.2 (Closed) LER 266/2002-001-00: Steam Generator Blowdown Valve Analyzed as Not Able to Close Against Differential Pressure.

On August 16, 2002, during the implementation of a new AOV evaluation and assessment program, licensee engineers determined that 1MS-5959, “Unit 1 ‘B’ Steam Generator Blowdown Isolation Valve,” may have been unable to shut against full differential pressure of 1085 psig. This was reported under 10 CFR 50.72(a)(2)(ix)(A) as an unanalyzed condition that had the potential to significantly degrade plant safety. The new AOV program was used to determine whether the valve’s performance would meet design basis function under prescribed operating conditions.

The licensee identified that during a seismic event, failure of 1MS-5959 to close against full differential pressure could present a challenge to the steam generator pressure boundary isolation function. Specifically, a seismic event was assumed to cause the loss of normal feedwater, initiation of AFW, failure of the steam generator blowdown line downstream valve 1MS-5959 to close, and rupture of the condensate storage tanks, the normal AFW supply. In addition, the worst case single failure was assumed to be the loss of safety-related direct current bus, D-01. Loss of D-01 was assumed to disable the low pressure suction trip mechanism for the Unit 1 turbine-driven AFW pump, 1P-29, and one of the two electric-driven AFW pumps, P-38A. This sequence of events would leave only the P-38B electric-driven AFW pump available to provide AFW flow to the ‘B’ steam generator. However, with 1MS-5959 unable to close due to the high differential pressure, a portion of the AFW flow to the 'B' steam generator would be diverted out the faulted blowdown pipe preventing the achievement of the design basis 200 gpm AFW flow reactor decay heat removal. Following diagnostic testing, adjustment of the AOV valve spring closing force, and successful completion of PMT activities, 1MS-5959 was restored to full operability on August 16.

The inspectors determined that inability to provide the design basis required AFW flow to the Unit 1 steam generators during a specific seismic event was more than minor since it affected the mitigating systems cornerstone objective of ensuring the capability of systems that respond to initiating events. Based on no seismic event having taken place and no actual loss of safety function of a mitigating system having occurred, this issue was determined to have very low safety significance (Green). This issue was included in CAP029065 and is dispositioned in Section 4A07.1 of this report.

.3 <u>(Closed) LER 2002-002-00</u>: Unit 1 'A' Train Reactor Protection Cable Routed in 'B' Train Cable Tray.

On September 28, 2002, during the installation of plant modification MR 00-003, the licensee identified an 'A' train engineered safeguards feature actuation circuit cable installed in a 'B' train cable tray. The licensee determined that this routing discrepancy had existed since original plant construction. The licensee entered the condition into their corrective action program as CAP029532, performed an extent of condition review on other similar Unit 1 and 2 cables, and routed a new cable in the appropriate cable tray.

Technical Specification 3.3.1 states that each reactor protection system function listed in TS Table 3.3.1-1 shall be operable. Table 3.3.1-1, Item 16, specifies that both trains of the SI input from the engineered safety feature actuation system be operable in Modes 1 and 2. Contrary to the above, the operability of 'A' train could not be supported due to inadequate separation with an 'A' train cable routed in a 'B' train cable tray. The licensee identified the problem while in Mode 6. However, Unit 1 had operated in Modes 1 and 2 with the train separation discrepancy in excess of the allowed outage time. Therefore, Unit 1 had been operated in a condition prohibited by TS 3.3.1. The inspectors reviewed this licensee-identified finding and determined that it met the criteria to be considered a NCV of TS 3.3.1. The finding was determined to be of very low safety significance and is dispositioned in Section 4OA7.2 of this report. This LER is considered closed.

.4 <u>(Closed) LER 50-266/2001-06</u>: Appendix R Requirements Not Satisfied For Unanalyzed Fire Induced Damage to the Auxiliary Feedwater System.

The licensee identified that motor-driven AFW pumps relied upon for safe-shutdown could be damaged during a fire. For a fire involving the Unit 1 turbine-driven AFW pump, the pump relied upon for safe shutdown, the 'B' motor-driven AFW pump, could also be damaged, resulting in no remaining mitigation capability for Unit 1. The failure to ensure safe shutdown capability is a violation of 10 CFR 50.48, "Fire Protection," and 10 CFR Part 50, Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979." Specifically, 10 CFR Part 50, Appendix R, Section III.G, requires that fire protection features be provided to ensure safe shutdown.

This violation was of greater than minor safety significance because the protection against the external factors (e.g., fire) attribute of the mitigating systems cornerstone was affected. The licensee evaluated the risk significance of this finding (documented by Calculation 2002-0031) and determined the violation was of very low safety significance due to the low probability that a fire would propagate and cause cable damage which would prevent the 'B' motor-driven AFW pump from operating. Specifically, the installed Halon suppression system for the area would likely be effective in extinguishing a surface fire. In the event that the automatic Halon system did not extinguish the fire initially, the licensee's analysis showed that it would take approximately 30 minutes for a fire in cable trays above the Unit 1 turbine-driven AFW pump to develop sufficient ceiling jet temperatures to cause damage to cables necessary for operation of the 'B' motor-driven AFW pump. Consequently, there would have been a high likelihood that manual suppression would have been effective. The NRC reviewed the licensee's evaluation and concurred with the results. The licensee has committed to perform modifications to protect cables necessary for operation of the 'B' pump. This violation is associated with a finding that is characterized by the Significance Determination Process as having very low risk significance (i.e., Green) and is being treated as a licensee-identified NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as Condition Report 01-3648 and is dispositioned in Section 4OA7.3 of this report.

.5 <u>(Open) LER 50-266/301/2002-003-00</u>: Possible Common Mode Failure of AFW Due to Partial Clogging of Recirculation Orifices.

On October 24, 2002, recirculation flow for the P-38A motor-driven AFW pump was slightly below the acceptance criterion during PMT. Initial investigations discovered that the flow restricting orifice in the recirculation line from the pump discharge to the condensate storage tanks was partially restricted. Following engineering analyses and evaluations, the licensee concluded on October 29, that the potential existed under specific conditions for the plugging of the orifices in the recirculation lines for all four AFW pumps. This could result in the loss of safety function if the discharge from the AFW pumps were throttled and inadequate flow existed in the recirculation line to preclude pump failure due to overheating. In accordance with 10 CFR 50.72(b)(3)(v) Event Notification 39330 was made on October 29. Interim compensatory actions included crew briefings, information posting, temporary procedure changes, and training for the operators.

The NRC dispatched a Special Inspection Team to Point Beach on October 31, to further review this issue. Analysis and evaluation of the susceptibility of the AFW system to this failure mode and assessment of the safety significance are ongoing. This LER and the results of the Special Inspection Team will be dispositioned in NRC Inspection Report 50-266/02-15; 50-301/02-15.

4OA4 <u>Cross-Cutting Findings</u>

.1 A finding described in Section 1R01.1 of this report had, as its primary cause, a human performance deficiency, in that, despite beginning freeze protection initiatives at an appropriate time, lack of coordination between licensee departments resulted in incomplete preparations prior to the onset of freezing temperatures. Not sufficiently coordinating cold weather preparation activities resulted in the Point Beach Nuclear Plant being exposed to 30 hours of below freezing temperatures over 6 nights prior to November 1, 2002.

.2 A finding described in Section 1R22.1 of this report had, as its primary cause, a human performance deficiency, in that, a technician calibrating feedwater controller LM-463F, because of inattention to detail, did not restore a dial setting after taking three as-found readings, adjusting two potentiometers, and taking three as-left readings. The result was an increase in the likelihood of an initiating event.

.3 A finding described in Section 4AO2.1 of this report had, as its primary cause, a human performance deficiency, in that, the licensee had not implemented effective corrective actions to address long-standing problems with flooding in manholes and had deferred the implementation of corrective actions with insufficient basis. The result was that the licensee had not performed any physical inspection of cables, cable splices, cable trays, cable tray supports, identified those cables susceptible to cable degradation in submerged environments, prioritized inspection or testing of cables, nor considered potential risk to the plant system, structures, and components based on a potential cable failure due to periodic submergence and long-term effects of the same.

.4 A finding described in Section 4AO3.1 of this report had, as its primary cause, a human performance deficiency, in that, inattention to the job at hand resulted in a vendor reassembling a pressurizer safety valve such that the valve would not have lifted at the TS-required setpoint. The result was Unit 2 having operated for an entire 18-month cycle with an inoperable pressurizer safety valve.

4OA5 Other

.1 Circumferential Cracking of Unit 1 RPV Head Penetration Nozzles (Temporary Instruction 2515/145)

a. Inspection Scope

The inspectors performed a review of the licensee’s activities in response to NRC Bulletin 2002-02, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs,” to verify compliance with applicable regulatory requirements. In accordance with the Bulletin, Unit 1 was characterized as belonging to the sub-population of plants with greater than 12 effective degradation years of plant operation. Effective degradation years account for a plant’s total operating time along with the temperature at which it was operated. Since a temporary instruction to support the review of licensee’s activities in response to NRC Bulletin 2002-02 had not been issued at the time of these inspection activities, the inspectors used the guidance in Temporary Instruction 2515/145, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” dated September 20, 2001, to assess Unit 1 RPV head inspection activities.

Point Beach responded to Bulletin 2002-02 by performing a direct visual examination of the top of the reactor vessel head and under head ultrasonic examinations of 49 control rod drive mechanism (CRDM) penetrations and one vent line nozzle. The inspectors interviewed inspection personnel, observed and evaluated data acquisition and analysis activities, observed portions of thermal sleeve repair activities, and reviewed procedures, examination records, and inspection reports to assess the licensee's efforts in conducting an "effective" visual examination of the top of the reactor vessel head, volumetric examinations of the CRDM and vent line nozzle material, and thermal sleeve repair activities. Finally, the inspectors reviewed CAP029839, "Record Discrepancy," which was initiated as a result of this inspection activity and discussed a vendor straightness gage used in CRDM 31 thermal sleeve repair activities that appeared to not meet minimum dimensional requirements.

b. <u>Findings</u>

<u>Summary</u>

No primary water stress corrosion cracks were detected in the Point Beach Unit 1 RPV head. Of the 49 nozzles examined, one contained a recordable fabrication indication in the nozzle wall. The remaining 48 nozzles and vent line did not contain any recordable indications. All nozzles with the exception of CRDMs 26, 27, 28, and 30 received 100 percent ultrasonic coverage. No boric acid deposits were found on the top of the RPV head.

<u>Evaluation of Inspection Requirements</u>

(1) Were the licensee's examinations performed by qualified and knowledgeable personnel?

<u>Top of Vessel Head Visual Examinations</u>
Yes. The direct visual examination of the head was performed by knowledgeable personnel certified to Level II or III as VT-2 examiners in accordance with programs meeting the American Society for Nondestructive Testing (ASNT) Recommended Practice SNT-TC-1A.

<u>Under-Vessel Head Ultrasonic Examinations</u>
Yes. The ultrasonic examinations were performed by contract personnel certified to Level II and III in accordance with programs meeting ASNT Recommended Practice SNT-TC-1A and CP 189. A portion of the UT personnel also had Electric Power Research Institute Performance Demonstration Initiative qualifications which met ASME Code Section XI, Appendix VIII requirements. In addition, the inspectors verified that essential variables, such as the type and frequency of the transducers used in the examinations, were consistent with those used during demonstration initiatives. Dye penetrant examinations were performed by contract personnel certified to Level II in accordance with ASNT Recommended Practice SNT-TC-1A.

(2) Were the licensee's examinations performed in accordance with approved and adequate procedures?

Top of Vessel Head Visual Examinations

Yes. The visual examinations were conducted in accordance with licensee nondestructive Examination Procedure NDE-757, "Visual Examination For Leakage of Reactor Pressure Vessel Closure Head Penetrations," Revision 1. This inspection included all vessel head penetrations (VHPs) and was intended to meet the visual quality standards established for VT-2 examinations as defined in Section XI of the ASME Code. The inspectors determined that the procedure was appropriate to detect and characterize boron deposits on the surfaces of the RPV head and CRDM annulus regions resulting from leakage of the RCS. Specific guidance was provided to ensure personnel performing the examination could distinguish boric acid crystal residue from asbestos insulation debris.

Under-Vessel Head Ultrasonic Examinations

Yes. The ultrasonic inspections were performed in accordance with Framatome ANP Nondestructive Examination Procedure 54-ISI-100-09, "Remote Ultrasonic Examination of Reactor Head Penetrations," dated September 9, 2002. The procedure provided for documentation of equipment setup; calibration; detection; location; and characterization of axial, circumferential, and off-axis inside diameter (ID) and outside diameter (OD) initiated flaws in the CRDM nozzle base metal.

In addition, the licensee performed an ultrasonic back wall reflection monitoring examination of the interference fit region above the J-groove weld. This 'leak-path' technique was a recently developed, vendor proprietary technology, the basis of which was empirical data from ultrasonic examinations occurring after March 2001 where the interference fit region had been scanned for VHPs with known leakage. The inspectors reviewed portions of the technical basis of the technique as described in the proprietary document titled, "Reactor Vessel Head Penetration Leak Path Qualification Report," dated February 6, 2002. The inspectors noted that good correlation had been obtained between leaking VHPs and ultrasonic leak-path data but that no data defining the detection limits or sensitivity of the technique had been provided in the subject report.

(3) Were the licensee's examinations adequately able to identify, disposition, and resolve deficiencies?

Top of Vessel Head Visual Examinations

Yes. The visual inspection procedure was qualified by demonstrating the ability to resolve characters of dimensions identified in ASME Code Section XI. The visual inspection was conducted by direct inspection methods capable of detecting and characterizing any leakage from cracking in VHP nozzles. Prior to the visual examination, asbestos insulation was removed in a controlled manner that did not compromise the identification of pre-existing boron deposits. Complete 360 degree circumferential visual examinations were performed for each VHP nozzle. Since the licensee's examinations did not identify any deficiencies, the inspectors did not assess efforts to disposition or resolve any visual indications.

Under-Vessel Head UT

Yes. Ultrasonic system calibrations were performed at sufficient intervals on calibration standards which contained ID and OD notches. The UT examinations were conducted from the inside of the VHP and data were recorded in a downward direction from 2 inches above the J-groove weld to the end of the nozzle. The examinations consisted of scanning for axial and circumferential flaws within the nozzle base metal using either the rotating or blade probe.

The rotating probe was used for open bore nozzles that did not contain thermal sleeves. The rotating probe consisted of a transducer head with multiple search units. The search units for the rotating probe were divided into two sets, one for the axial beam direction and one for the circumferential beam direction. The rotating probe search units used combinations of 0, 30, 45, 55, 60, and 65 degree angle search units. The blade probe was used for nozzles that contained thermal sleeves. The circumferential blade probe was designed to emit ultrasound along the long axis of the nozzle using an angle beam transducer. The axial blade probe was designed to emit ultrasound circumferentially around the nozzle and also used an angle beam transducer.

Complete coverage was obtained on all VHPs with the exception of seven penetrations located on the periphery for the head. Complete UT coverage for penetrations 26, 27, 28, 30, 31, 32, and 33 could not be initially achieved due to close dimensional tolerances between the nozzle and thermal sleeves. In descending order, the extent of initial UT coverage for these penetrations was approximately 78 percent, 66 percent, 52 percent, 50 percent, 31 percent, 18 percent, and 3 percent. Following discussions with NRC management, the licensee removed the thermal sleeves for four CRDMs: 1, 31, 32, and 33. Removal of the thermal sleeves allowed for full UT coverage on CRDMs 31, 32, and 33 and use of the rotating probe for enhanced indication characterization on CRDM 1.

Finally, the inspectors noted that the vendor used the zero degree longitudinal wave to profile the location of the upper and lower edges of the nozzle-to-head weld. Examination Procedure 54-ISI-100-09 directed the analyst to determine the location of the weld for each recorded flaw and at approximate 30 degree intervals along the circumference when flaw indications were recorded. While comparing UT data from various CRDM 1 scans, the inspectors became aware of variances in the weld profile definition. The inspectors learned that defining the precise location of the upper and lower edges of the weld profile was left to the discretion of the analyst. Although not directly applicable to Point Beach Unit 1, the inspectors considered that this variance could result in meaningful differences in the remaining service life determinations of indications evaluated in other RPV heads for other licensees. Based on this observation, the inspectors recommended to the NRR staff that licensees consider developing guidelines that would include demonstration of more objective and quantifiable weld profiles. Improved weld profile guidelines would eliminate analyst subjectivity, provide a more precise determination of the remaining amount of sound material for a given penetration and indication, and lead to better remaining service life decisions for those RPV heads determined to contain primary water stress corrosion cracks.

(4) *Were the licensee's examinations capable of identifying the primary stress corrosion cracking phenomenon described in the Bulletin?*

Top of Vessel Head Visual Examinations
Yes. The inspectors determined through direct observations, interviews with inspection personnel, reviews of procedures and inspection reports, and reviews of video tape documentation that the licensee was capable of detecting and characterizing leakage from cracking in VHP nozzles. The inspectors determined that the inspection personnel had access to all the head penetrations, 49 in total plus the 3/4" head vent, with no obstructions or interferences.

Under-Vessel Head Ultrasonic and PT Examinations
Yes for the VHP nozzle base metal material. The UT search units were designed to detect flaws in the penetration tube and this equipment had been used to detect cracking in CRDM penetration tubes removed from the Oconee Nuclear Power Station and Electric Power Research Institute/Modification Rework Package Mockup G. The calibration standard used was of similar material and dimensions as the head penetration tubes. This standard contained both axial and circumferential oriented notches located at the inside and outside surface. The inspector concluded that the UT method used would likely detect primary water stress-corrosion cracking (PWSCC) in the penetration tube.

Due to differences in the search unit configurations, variances in the J-groove dimensions, and lack of any J-groove weld demonstration data, the inspectors determined that the UT technique used would not be effective for detection of PWSCC that was entirely within the J-groove weld attaching the penetration tubing to the vessel head. During the course of the UT examinations, however, the inspectors noted the appearance of several inclusions beyond the OD of the nozzle base metal in the J-groove weld material. Ultrasonically, these inclusions appeared as symmetric point reflectors and indicated that at least some ultrasound had traveled into the weld material. In attempting to characterize indications on CRDM 1, the inspectors also noted that the licensee had completed two PT examinations on the J-groove weld surface. No OD, surface-connected, J-groove weld PT indications were noted during either of the examinations, although the second PT examination recorded one linear indication on the OD surface of the nozzle that was 5/64" long, circumferentially oriented, and located approximately 1-1/4" from the end of the nozzle, and approximately 1/4" below the weld toe.

(5) *What was the condition of the reactor vessel head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?*

Top of Vessel Head Visual Examinations

The Unit 1 RPV head had 3"-thick block contoured asbestos insulation. The 3" blocks were in direct contact with, but not bonded to, the RPV head. The blocks were coated with 1/4"-Fiberfax cement which was sealed with a waterproof coating. The inspectors verified that prior to the visual examinations, the licensee had completely removed the insulation. Through discussions with inspection personnel and viewing of the videotape, the inspectors determined that the as-found pressure vessel head condition was relatively clean with no examination viewing obstructions. The inspection personnel fully examined the 49 VHPs, including the 3/4" head vent.

Under-Vessel Head Ultrasonic Examinations
The surface of the inner bore of the CRDM penetrations was sufficiently smooth for the UT examinations; however, the blade probe experienced difficulty in accessing the nozzle ID on CRDMs 26, 27, 28, 30, 31, 32, and 33 due to close dimensional clearances between the VHP nozzle and thermal sleeves. This resulted in coverage limitations and the damaging of several blade probes during multiple attempts to increase coverage. Following discussions with NRC management, the licensee removed the thermal sleeves for CRDMs 31, 32, and 33, allowing 100 percent coverage with the rotating probe. No boric acid deposits on the top of reactor vessel head, subsequent full ultrasonic coverage on the three most limited peripheral CRDMs, and fracture mechanics analysis considerations provided reasonable assurance of the integrity of the uninspected sectors of CRDMs 26, 27, 28, and 30, each of which had greater than 50 percent ultrasonic coverage.

(6) *Could small boron deposits, as described in the bulletin, be identified and characterized?*

Top of Vessel Head Visual Examinations
Yes. The inspectors determined through direct observations, interviews with inspection personnel, reviews of procedures and inspection reports, and reviews of video tape documentation that small boron deposits, as described in the Bulletin, could be identified and characterized. The inspectors noted that no boric acid deposits were found on the 49 VHPs, including the 3/4" head vent.

(7) *What materiel deficiencies (associated with the concerns identified in the bulletin) were identified that required repair?*

Top of Vessel Head Visual Examinations
None. Through direct observations, interviews with inspection personnel, reviews of procedures and inspection reports, and reviews of video tape documentation, the inspectors determined that inspection personnel did not identify any materiel deficiencies associated with the 49 VHPs, including the 3/4" head vent.

Under-Vessel Head Ultrasonic Examinations
Four thermal sleeves were repaired during the licensee’s RPV inspection not for material deficiency reasons but to allow for full UT coverage on CRDMs 31, 32,

and 33 and use of the rotating probe for enhanced indication characterization on CRDM 1.

CRDM 1 was scanned a total of 5 times using various ultrasonic techniques. In addition, two PT examinations were performed. The final examination results of CRDM 1 with the rotating probe indicated that there were no PWSCC crack indications in the nozzle. The inspectors reviewed extensive UT data and confirmed this conclusion. Due to the presence of a thermal sleeve, the examination sequence of CRDM 1 began with the circumferential blade probe. The first scan on September 24, revealed several areas of reduced back wall amplitude in the region of the J-groove weld. A second scan with the circumferential blade probe was performed on the same day and the results confirmed the findings of the initial scan. As a result, the indications were initially classified as OD axial indications.

At the completion of the second circumferential blade probe scan, the licensee determined that a PT test would be utilized to validate the UT indications. The results of the PT were negative and did not confirm the UT indications. At this point, the circumferential blade probe data was independently reviewed by other vendor Level III UT analysts and the determination was made to treat the circumferential blade probe signals as axial indications based on the pattern of the reduced back wall response. The licensee then examined CRDM 1 using the axial blade probe on September 25. The axial blade probe did not detect any back wall signal reductions. To further define the axial indications, a third circumferential blade probe examination was conducted on September 26. This examination was conducted with a different serial number probe than previous circumferential blade probe scans and used a 1 degree versus 3 degree circumferential index increment. The results of the third circumferential blade probe scan confirmed both of the previous examinations and 12 OD axial indications were documented on a CRDM 1 UT examination data sheet on September 28, 2002. The licensee also considered that the first PT examination might not have been adequate for the detection of tight cracks since the examination had utilized the shortest allowable dwell time. Following nozzle OD and surrounding J-groove weld surface preparation using a flapper wheel, a second PT examination was performed using the maximum allowable dwell times. The results of the second PT test did not confirm the UT indications but did identify one linear indication on the nozzle OD. The PT indication was 5/64" long, circumferentially oriented, approximately 1-1/4" from the end of the nozzle, and approximately 1/4" below the weld toe . The PT indication was determined to be unrelated and not part of the multiple axial indications observed with the circumferential blade probe.

Point Beach subsequently removed the thermal sleeve from CRDM 1 to allow for rotating probe access and final reconciliation of the previous examination results. CRDM 1 was scanned with the rotating probe on September 30. In each of the displays presented for the rotating probe, the axial indications detected with the circumferential blade probe were not present. Based on additional and similar techniques used on the rotating probe as compared to the circumferential blade probe, repeatable detection of fabrication indications, and the lack of any axial indications such as those detected by the circumferential blade probe, the licensee concluded that the indications seen with the circumferential blade probe were not PWSCC.

The inspectors questioned the licensee's CRDM 1 conclusion and reviewed raw rotating and blade probe UT data with a vendor level III UT analyst on an analysis station; compared actual Oconee crack characteristics with the Point Beach CRDM 1 indication characteristics; interviewed two vendor welders involved with RPV head manufacture to gain an understanding of the manual processes used in the CRDM 1 welding process; and performed ray traces for all the transducers on the rotating and blade probes. After performing the above reviews, the inspectors agreed that the indications in CRDM 1 were not actual PWSCC cracks but rather considered the indications to be indicative of long shallow grooves on the OD of the nozzle base metal caused by the original manufacturing process. The inspectors considered the multiple axial indications on CRDM 1 to be characteristic of the ultrasonic signals that would be caused by a pencil grinder that had touched the nozzle OD base metal while attempting to remove manual shielded metal arc welding slag inclusions in the narrow groove region between the OD of the nozzle base metal and RPV head weld buttering for a CRDM located on the top-dead-center of the RPV head.

Based on this observation, the inspectors recommended to the NRR staff, that utilities consider the review of other licensees' top-dead-center CRDM UT data that has already been acquired to determine if similar multiple axial indication on the OD of the nozzle base metal exist. If similar indications were found by other licensees, mockups of manufacturing flaws could be produced with accompanying demonstration initiatives. This effort could lead to improved vendor analysis guidelines which would be better able to distinguish between actual PWSCC cracks and indications caused by aspects of the original manufacturing process. In addition, a better understanding of manufacturing induced indications would reduce radiation exposures during future examinations and help to eliminate unnecessary repairs.

(8) What, if any, significant items that could impede effective examinations and/or ALARA issues were encountered?

The inspectors verified that, upon removal of the asbestos head insulation, there were no impediments to the examinations. The ALARA projected dose for all head examinations was 31.5 person-rem. The actual dose received was 28.060 person-rem. The shroud and new RPV head insulation was installed with viewing ports to aid future inspections of the head and to reduce dose associated with insulation removal.

.2 <u>Completion of Appendix A to TI 2515/148, Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures, Revision 1</u>

The inspectors completed the pre-inspection audit for interim compensatory measures at nuclear power plants, dated September 13, 2002.

.3 Review of World Association of Nuclear Operators Peer Review Report

The inspectors completed a review of the final report for the World Association of Nuclear Operators Peer Review, November 2001 Evaluation, dated August 15, 2002.

4OA6 Meetings

.1 Exit Meeting

The resident inspectors presented the inspection results to Mr. A. Cayia and other members of licensee management on January 6, 2003. The licensee acknowledged the findings presented. No proprietary information was identified.

.2 Interim Exit Meeting

Interim Exits were conducted for:

- Senior Official at Exit: T. Taylor, Point Beach Plant Manager
  Date: October 4, 2002
  Proprietary: No
  Subject: Access control to radiologically significant areas, ALARA planning and control, and performance indicator verification for occupational exposure control effectiveness.

- Senior Official at Exit: Mr. M. Fencl, Security Manager, Point Beach/Kewaunee
  Date: October 15 and 31
  Proprietary: Yes. Proprietary information was received and reviewed by the inspector and subsequently returned to the licensee. Licensee attendees at the interim exit acknowledged the findings presented and did not identify any potential report input as proprietary information.
  Subject: Safeguards

- Senior Official at Exit: Mr. A. Cayia, Site Vice-President, Point Beach Nuclear Plant
  Date: October 25
  Proprietary: Yes. Proprietary information was received and reviewed by the inspector and subsequently returned to the licensee. Licensee attendees at the interim exit acknowledged the findings presented and did not identify any potential report input as proprietary information.
  Subject: Unit 1 biennial inservice inspection activities and TI 2515/145, Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles

- Senior Official at Exit: Mr. P. Smith
  Date: November 14
  Proprietary: No
  Subject: Results of licensed operator requalification testing for 2002 and applicability of NRC Inspection Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)"

- Senior Official at Exit: Mr. A. Cayia, Site Vice-President, Point Beach Nuclear Plant (via telephone)
  Date: November 15
  Proprietary: No
  Subject: Partial identification and resolution of problems on a licensee-identified fire protection issue.

4OA7 Licensee-Identified Violations

The following violations of very low significance were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the US NRC Enforcement Manual, NUREG1600, for being dispositioned as NCVs.

Cornerstone: Mitigating Systems

.1 Code of Federal Regulations 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures be established and provide for verifying or checking the adequacy of design. Contrary to this requirement, prior to August 16, 2002, the licensee did not establish measures to ensure that the Unit 1 'B' steam generator blowdown isolation valve, 1MS-5959, would have closed during a seismic event combined with the loss of direct current bus D-01. The result was the inability to provide 200 gpm AFW flow to the Unit 1 steam generators necessary for post-accident decay heat removal design requirements.

.2 On September 28, 2002, during the installation of plant modification MR 00-003, the licensee identified an 'A' train engineered safeguards feature actuation circuit cable installed in a 'B' train cable tray. As a result, the licensee declared the 'A' train SI signal to the reactor protection system inoperable due to improper cable separation. Technical Specification 3.3.1 states that each reactor protection system function listed in TS Table 3.3.1-1 shall be operable. Table 3.3.1-1, Item 16, specifies that both trains of the SI input from the engineered safety feature actuation system be operable in Modes 1 and 2. Contrary to the above, the licensee had operated Unit 1 in Modes 1 and 2 with the train separation discrepancy in excess of the allowed outage time and, as such, in a condition prohibited by TS 3.3.1. The licensee entered the issue into their corrective action program as CAP029532 and submitted an LER (2002-002-00).

This finding is more than minor because it occurred as a result of a performance deficiency that was associated with the design control mitigating system cornerstone attribute and affected the mitigating cornerstone objective to ensure the availability, reliability, and capability of a system that responds to initiating events to prevent undesirable consequences such as core damage. The inadequate separation between the ‘A’ and ‘B’ trains SI signal to the reactor protection system could potentially affect the reliability of mitigating systems during a fire in the cable spreading room. The inspectors screened the finding using Phase 1 Significance Determination Worksheet of Manual Chapter 0609, Appendix A. The finding was determined to be of very low safety significance (Green) since the finding could be considered a design deficiency that was confirmed not to result in a loss of safety function per Generic Letter 91-18.

.3 10 CFR 50.48, “Fire Protection,” and 10 CFR Part 50, Appendix R, “Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979,” require that safe shutdown capability in the event of a fire be ensured. As reported in LER 50-266/2001-06, the licensee identified that a Unit 1 turbine-driven AFW pump fire could potentially damage the AFW pump relied upon for safe shutdown with no remaining shutdown capability. The NRC and the licensee determined that the issue was of very low safety significance (Green) due to credit for automatic and manual fire suppression. The licensee committed to perform modifications to address this issue. This violation is in the licensee’s corrective action program as Condition Report 01-3648 and is also discussed above in Section 4OA3.4.

KEY POINTS OF CONTACT

<u>Licensee</u>

J. Anderson, Production Planning Group Manager
L. Armstrong, Design Engineering Manager
J. Boesch, Maintenance Manager
A. Cayia, Site Vice-President
M. Fencl, Security Manager, Kewaunee/Point Beach
F. Flentje, Senior Regulatory Compliance Specialist
D. Gehrke, Nuclear Oversight Supervisor
N. Hoefert, Engineering Programs Manager
R. Hopkins, Nuclear Oversight Supervisor
B. Kopetsky, NMC Security Coordinator, Kewaunee/Point Beach
C. Krause, Regulatory Compliance
J. Lindsay, RP General Supervisor
J. McCullum, Security Coordinator
L. Schofield, Regulatory Assurance
D. Schoon, Operations Manager
C. Sizemore, Training Supervisor
P. Smith, Operations Training Supervisor
J. Strharsky, Assistant Operations Manager
T. Taylor, Plant Manager
S. Thomas, Radiation Protection Manager
R. Turner, Inservice Inspection Coordinator
T. Webb, Licensing Manager

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-266/301/02-13-01	FIN	Insufficient Preparation for Cold Weather Conditions (Section 1R01.1)
50-266/02-13-02	FIN	Mis-Calibration of Unit 1 Steam Generator Level Setpoint Programmer Module (Section 1R22.1)
50-266/301/02-13-03	FIN	Inadequate and Untimely Corrective Actions Relating to Flooding of Manholes Containing Safety and Non-Safety Related Cables (Section 4OA2.1)
50-301/02-13-04	NCV	Pressurizer Safety Valve Failed to Lift at Test Pressure (Section 4AO3.1)
50-266/2002-002-00	LER	Unit 1 ‘A’ Train Reactor Protection Cable Routed in ‘B’ Train Cable Tray (Section 4OA3.3)
50-266/2001-006-00	LER	Appendix R Requirements Not Satisfied For Unanalyzed Fire Induced Damage to the Auxiliary Feedwater System (Section 4AO3.4)
50-266/301/2002-003-00	LER	Possible Common Mode Failure of AFW Due to Partial Clogging of Recirculation Orifices (Section 4AO3.5)

Closed

50-301/02-10-05	URI	Inoperable Unit 2 Reactor Coolant System Safety Valve for Entire 18-Month Operating Cycle, December 2000 to April 2002 (Section 4OA3.1)
50-301/2002-002-00 50-301/2002-002-01	LER	Pressurizer Safety Valve Failed to Lift at Test Pressure (Section 4AO3.1)
50-266/2002-001-00	LER	Steam Generator Blowdown Valve Analyzed as Not Able to Close Against Differential Pressure (Section 4OA3.2)
50-266/98009-03(DRS); 50-301/98009-03(DRS):	IFI	Containment Hatch Requirement, Maintenance Rule, 10 CFR 50.65 (Section 1R12.2)
50-266/301/02-13-01	FIN	Insufficient Preparation for Cold Weather Conditions (Section 1R01.1)
50-266/02-13-02	FIN	Mis-Calibration of Unit 1 Steam Generator Level Setpoint Programmer Module (Section 1R22.1)

50-266/301/02-13-03	FIN	Inadequate and Untimely Corrective Actions Relating to Flooding of Manholes Containing Safety and Non-Safety Related Cables (Section 4OA2.1)
50-301/02-13-04	NCV	Pressurizer Safety Valve Failed to Lift at Test Pressure (Section 4OA3.1)
50-266/2002-002-00	LER	Unit 1 ‘A’ Train Reactor Protection Cable Routed in ‘B’ Train Cable Tray (Section 4OA3.3)
50-266/2001-006-00	LER	Appendix R Requirements Not Satisfied For Unanalyzed Fire Induced Damage to the Auxiliary Feedwater System (Section 4OA3.4)

Discussed

None

LIST OF ACRONYMS USED

ACE	Apparent Cause Evaluation
AFW	Auxiliary Feedwater
ALARA	As-Low-As-Is-Reasonably-Achievable
AMSAC	Anticipated Transient Without Scram Mitigation System Actuation Circuitry
AOP	Abnormal Operating Procedure
AOV	Air-Operated Valve
AR	Action Request
ARP	Alarm Response Procedure
ASME	American Society of Mechanical Engineers
ASNT	American Society for Nondestructive Testing
ATWS	Anticipated-Transient-Without-Scram
CA	Corrective Action
CAP	Corrective Action Program
CE	Condition Evaluation
CFR	Code of Federal Regulations
CI	Containment Integrity
CL	Checklist
CRDM	Control Rod Drive Mechanism
DBD	Design Basis Document
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
°F	Degrees Fahrenheit
FIN	Finding
FSAR	Final Safety Analysis Report
FZ	Fire Zone
gpm	Gallons Per Minute
HELB	High-Energy Line Break
HRA	High Radiation Area
I&C	Instrument and Control
ID	Inside Diameter
IFI	Inspection Follow Item
ISI	Inservice Inspection
IT	Inservice Test
LER	Licensee Event Report
mrem/hr	Millirem/hour
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NP	Nuclear Power Business Unit Procedure
NPM	Nuclear Plant Memo
NRC	Nuclear Regulatory Commission
OD	Outside Diameter
OI	Operating Instruction
OS	Occupational Radiation Safety

OWA	Operator Workaround
PAB	Primary Auxiliary Building
PBNP	Point Beach Nuclear Plant
PC	Periodic Check Procedure
PI	Performance Indicator
PMT	Post-Maintenance Testing
psig	Pounds Per Square Inch - Gauge
PT	Dye Penetrant
PWSCC	Primary Water Stress-Corrosion Cracking
Radwaste	Radioactive Waste
RCE	Root Cause Evaluation
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RMP	Routine Maintenance Procedure
RPV	Reactor Pressure Vessel
RTD	Resistance Temperature Detector
RWP	Radiation Work Permit
SDP	Significance Determination Process
SFP	Spent Fuel Pool
SI	Safety Injection
SW	Service Water
TEDE	Total Effective Dose Equivalent
TS	Technical Specification
U2R25	Unit 2, Refueling Outage 25
U1R27	Unit 1, Refueling Outage 27
U1R28	Unit 1, Refueling Outage 28
URI	Unresolved Item
UT	Ultrasonic Testing
VAC	Volts Alternating Current
VDC	Volts Direct Current
VHP	Vessel Head Penetration
VHRA	Very High Radiation Area
WO	Work Order

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PC 49 Part 2, Turbine Hall Ventilation Unit 2, Revision 9

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PC 49 Part 5, Cold Weather Checklist, Outside Areas and Miscellaneous, Revision 15

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OI 106, Facade Freeze Protection, Revision 18

OI 38, Circulating Water System Operation, Revision 29

Design Basis Document (DBD) 11, Safety Injection and Containment Spray System Component Parameter Worksheets, Section 3.4, Revision 0

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System Engineer List of PC 49 Freeze Protection Issues, received October 31, 2002

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NRC AEOD Engineering Evaluation Report 97-03, Nuclear Power Plant Cold Weather Problems and Protective Measures, December 1997

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DBD-19, Design Basis Document 125 VDC, Revision 2

Final Safety Analysis Report (FSAR), Volume 4, Chapter 8.7, 125 VDC Electrical System, June 2000

Bech 6118 E-6, Sheet 1, Single Line Diagram 125 Volt DC System, Unit 0, April 23, 1990

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ORT 3B, Safety Injection Actuation With Loss Of Engineering Safeguards AC (Train B), Unit 2, Revision 33

ORT 3A, Safety Injection Actuation With Loss Of Engineering Safeguards AC (Train A), Unit 1, Revision 36

ORT 3B, Safety Injection Actuation With Loss Of Engineering Safeguards AC (Train B), Unit 1, Revision 33

FSAR, Volume 4, Chapter 8.6, 120 VAC Electrical System, June 2000

DBD-17, Design Basis Document 120 VAC, Revision 1

MDB 3.2.11 1Y01, Nuclear Power Business Unit Master Data Book Instrument Panels, Unit 1, Revision 5

MDB 3.2.12 D11, Nuclear Power Business Unit Master Data Book Instrument Panels, Unit 1, Revision 14

MDB 3.2.12 D26, Nuclear Power Business Unit Master Data Book Instrument Panels, Unit 1, Revision 2

Bech 6118 E-7 Sheet 10, Connection Diagram 120V AC Instrument Bus Distribution Panel 1Y-01, Unit 1, Revision 01

Special Instruction G-4087, Special Model 67HSTG2 Automatic-Manual Station, Foxboro Manual

500B728 Sheet 58, Foxboro Shelf 1C03-28 Main Control Board Component Wiring, Revision 4, January, 29, 2000

Foxboro 10688 PW-14 Sheet 1, Wiring Diagram-Term. Blocks Reactor Control System Rack 1-FW (1C127, Revision 10, January 22, 2000

WEST 499B466 Sheet 266B, Elementary Wiring Diagram 4160V Switchgear Bus 1A05 Undervoltage & Diff. L.O. Relays, Unit 1, Revision 5

WEST 499B466 Sheet 296B, Elementary Wiring Diagram 4160V Switchgear Bus 2A05 Undervoltage & Diff. L.O. Relays, Unit 2, Revision 4

WEST 499B466 Sheet 219, Elementary Wiring Diagram DC Control Power Transfer, Unit 0, Revision 13

WEST 499B466 Sheet 286A, Elementary Wiring Diagram 4160V Switchgear 2A05 Cubicle 72 Bus Tie Dummy Breaker, Unit 2, Revision 3

<u>1R05</u> <u>Fire Protection</u>

Point Beach Nuclear Plant Fire Hazards Analysis Report, Fire Zone 322 - Turbine Building Operating Floor - Unit 1, August 17,

<u>1R06</u> <u>Flood Protection Measures</u>

Preventative Maintenance Procedure INSP-EJ, Inspect Expansion Joint For Embrittlement

<u>1R08</u> <u>Inservice Inspection Activities</u>

CAP029754, NDE [Nondestructive Examination] Data Sheet Had The Wrong Instrument Setting, October 6, 2002

CAP029756, Suggested Enhancement To NDE Data Sheet NDE-750.1, October 9, 2002

CAP029201, Poor Timeliness In Resolving Potential Plant Problem, September 3, 2002

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CAP013801, Presence of Boric Acid Residue Not Recorded, April 11, 2001

CAP013906, Spring Hanger Concerns, April 26, 2001

CAP000900, Spent Fuel Pool Heat Exchanger Fouling, August 9, 2001

CAP005467, G-01 & G-02 Emergency Diesel Coolers Concerns, August 9, 2001

CAP001985, NRC Commitment To Inspection of Unit 2 Internal Lift Rig Not Met, January 25, 2002

CAP002655, Support SI-1501R-3-2H2 Apparently Has Wrong Type of Spring Can Installed, March 22, 2002

CAP003032, Evaluation of ISI [Inservice Inspection] Examinations Are Creating Problems for AR Engineering, April 25, 2002

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CAP013928, Keyway Snubber Mounting, May 1, 2001

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NDE-168, Manual Ultrasonic Examination of RPV Flange-To-Upper Shell Weld, Revision 8

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Ultrasonic Examination Record, T-034B A/B/C/D Safety Injection Accumulator Level Transmitter Nozzles, September 27, 2002

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Ultrasonic Piping Examination Record, Pipe to Valve SI-867B, AC-10-SI-1001-19, September 26, 2002

Radiographic Examination Report, Unit 1 Pressurizer Safe End To Relief Nozzle, EDMS Location 2002-0151, March 24, 1998

Radiographic Examination Report, Unit 1 Pressurizer Spray Nozzle - Safe End, EDMS Location 2002-0077, April 29, 2001

Radiographic Examination Report, Unit 2 Pressurizer Spray Nozzle - Safe End, EDMS Location 2002-1375, May 2, 2002

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Visual Examination Record, RPV Closure Head Nuts 1 thru 16, September 22, 2002

Remote Visual Examination Record, RPV Interior Surfaces, September 25, 2002

NDE-451, Visible Dye Penetrant Examination Temperature Applications, 45 to 125F, Revision 20

NDE-750, Visual Examination (VT-1) Of Nuclear Power Plant Components, Revision 21

NDE-756, Remote Visual Examination of Reactor Pressure Vessel Interior and Components, Revision 2

Visual Examination (VT-3) of Nuclear Power Plant Components, Revision 10

NDE-173, PDI Generic Procedure for the Ultrasonic Examination of Austenitic Piping Welds, Revision 4

Plant Modification MR-02-035, Unit 1 Safety Injection Accumulator Nozzle Upgrade to Remove Nozzle Flaws, September 29, 2002

Point Beach Calculation PBCH-01Q-301, Accumulator Tank Repair Stress Analysis, September 28, 2002

WO 0212695, T-034A SI Accumulator Tanks, September 29, 2002

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PBNP - Unit 1, Inservice Inspection Results Summary, Interval, Period 3, Outage 3 (U1R26)

NDE-165, Manual Ultrasonic Examination of Reactor Pressure Vessel Threads In Flange, Revision 9

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Nuclear Power Business Unit Procedure (NP) 7.2.5, Repair/Replacement Program, Revision 9

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WO 9925546, P-32A SW Pump Discharge Expansion Joint, November 17, 2001

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SG0098, Design Basis SGTR, Revision 0, January 2, 2002

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1R12 Maintenance Rule Implementation

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E-1 Report for UO8B2 (Work Week Schedule), September 29, 2002

E-1 Report for V01A1 (Work Week Schedule), November 3, 2002

E-1 Report for V04B2 (Work Week Schedule), November 24, 2002

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Daily Updates of Core Damage Risk Profile (Safety Monitor), November 3 - 9, 2002

Daily Update of Core Damage Risk Profile (Safety Monitor), November 24 - 30, 2002

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<u>1R14</u> <u>Personnel Performance During Non-Routine Plant Evolutions</u>

CAP030328, Damage to PAB Crane Pendant Cable, December 5, 2002

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CAP029732, U1R27 Upper Cavity FME, October 7, 2002

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CA025902, Implement Recommendations of CA028816, July 25, 2002

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WO 9945610, P-38A AFP Discharge Control Operator, Unit 0, October 23, 2002

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WO 0200855, Change Oil In 1P-14B Containment Spray Pump, November 13, 2002

IT 05, Containment Spray Pumps and Valves (Quarterly) Unit 1, Revision 45

1R20 Refueling and Outage Activities

CL 20, Post Outage Containment Closeout Inspection Unit 1, Revision 10

CL 2B, Mode 6 to 5 Checklist, Unit 1, Revision 2

CL 2C, Mode 5 to 4 Checklist, Unit 1, Revision 1

CL 2D, Mode 4 to 3 Checklist, Unit 1, Revision 0

CL 2E, Mode 3 to 2 Checklist, Unit 1, Revision 1

CL 2F, Mode 2 to 1 Checklist, Unit 1, Revision 0

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OP 4D Part 3, Draining the Reactor Cavity and Reactor Coolant System, Revision 12

OP 4F, Reactor Coolant System Reduced Inventory Requirements, Revision 17

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OP 1C, Startup to Power Operation, Revision 46

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1R22 Surveillance Testing

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CAP029861, Unit 1 Improper S/G [Steam Generator] Levels During Load Ramp, October 18, 2002

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CAP002105, Radworker Found with Discrete Radioactive Particle, February 6, 2002

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CAP003319, High Radiation Area Improperly Posted, May 16, 2002

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WO Work Plan, Reactor Vessel Keyway Snubber, October 1, 2002

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CAP003021, Scaffold Removed from Around RV Head Prior to Work Completion, April 24, 2002

CAP028378, Unexpected Dose Rates in 26' Blowdown Evaporator, June 4, 2002

CAP002802, Unexpected High Levels of Contamination Found on Transfer Dolly, April 10, 2002

CAP002885, Radworkers With Poor ALARA Work Practices, April 17, 2002

CAP029321, U1R27 Scaffold Activity Stopped Due to High Dose Rates from CAMP-110, September 15, 2002

CAP029372, Unanticipated Dose Rate Increases During Keyway Entry, September 17, 2002

CAP029546, 1CV-296 Repairs Exceeding Initial Dose Projections, September 26, 2002

CAP029641, U1R27 CFC Modification Is Greater than 125% of the Estimated Dose, September 30, 2002

CAP029672, Elevated Dose Rates After CAMP- 110 Cleanup, October 3, 2002

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RWP 02-149, RV Head UT Inspection Under Head (FRAMATOME), Revision 0

RWP 02-156, Containment Accident Fan Modification, Revision 0

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RWP 02-184, RV Head Nozzle Repair, Revision 0

RWP 02-216, Reactor Head O-ring Removal, Revision 0

RWP 02-235, Upper Reactor Cavity Decontamination, Revision 0

RWP 02-239, Lower Reactor Cavity Decontamination, Revision 0

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RWP 02-265, RV Head-Shroud Removal/Replacement, Revision 0

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Listing of Highest Doses, Rem TEDE 2002, by Work Groups, June 30, 2002

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Radiological Survey Maps, Unit #1, "C" Containment Fan Cooler are, Under Reactor In-Core "Keyway" Area, and Reactor Head/Thermal Sleeve #1 Work Area

RP Activities Work Schedule, Week of September 30, September 30, 2002

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TEDE ALARA Evaluation, Upper Internals Lift Rig Inspection, April 12, 2002

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U1R27 Outage Dose Graphic, September 27, 2002

U1R27 Exposure, Listing by Work Evolution, with Emergent Work Included, October 1, 2002

U1R27 Exposure, Listing by Work Group, with Emergent Work Included, September 23, 2002

U1R27 RCS Activity Trend (as Co-58) Graphic, September 22, 2002

Work Required to Meet the Head-set Milestone Schedule, Week of September 30, September 30, 2002

ALARA Review Log

Listing of Additional Dose During U1R27 (through 10/1/02)

Outage Daily Dose 10 Days, Total Dose for Each (Outage Plus Non-Outage), Previous Five Outages

Point Beach Nuclear Plant, Three Year Rolling Average Radiation Dose (Person-rem/unit), Graphic Chart, 1976-2001

U1R27 Outage Dose, Table Listing by Work Evolution

2002 Dose, 1/1/02 - 12/31/02, Sorted by RWP Number

<u>3PP4</u> <u>Physical Protection - Security Plan Changes</u>

Point Beach Security Safeguards and Contingency Plan, Revision 1, August 1, 2002

Point Beach Security Safeguards and Contingency Plan, Revision 2, October 8, 2002

Point Beach Security Training and Qualification Plan, Revision 1, August 1, 2002

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<u>4OA01</u> <u>Performance Indicator Verification</u>

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OI 35A, Standby Emergency Power Alignment, Revision 8

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PBNP Mitigating System Cornerstone Monthly Unavailability and Verification for the Emergency Alternating Current Sources, October 2001 through September 2002

Operations Narrative Logs, October 2001 through September 2002

4OA02 Identification and Resolution of Problems

RCE 000051, Untimely Corrective Action - Failure to Establish Qualification Files for Equipment, June 13, 2002

Operation Determination CR 98-0164/CAP001532, Environmental Qualification/High Energy Line Break in Auxiliary Building, Part 1, Revision 11, Part 2, Revision 5

Operability Recommendation OPR000011, Request Revision 9 of Operability Determination for CR 98-0164, April 8, 2002

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CAP001559, High Energy Line Break [HELB] in PAB, January 18, 1998

CAP001582, S&L CALC M-09334-357-HE.1 Environmental Effects of HELB Outside Containment, July 19, 1998

CAP002777, Untimely Corrective Action–Failure to Establish Qualification Files for Equipment, April 8, 2002

CA002731, Verify That the SSC for Each Unit Has Been Restored to “Full Qualification” per NP 5.3.7 and notify RJH1 or CTP to Remove This Issue From The “Operable, but Degraded” List, March 25, 1998

CA002806, Per NPM 99-0041, Design and Install Doghouses With Doors and Hatch Cover on 45' Elevation of the PAB, January 21, 1999

CA002812, Provide a Documented Analysis of Door 19 With Windows to Resolve the Condition Described in CR 99-3241, Where It Was Noted That Door 19 Had Been Inadvertently Credited in HELB Calculations, December 17, 1999

CA004302, Notify KNPP Of This Level A Issue [CAP002277], April 15, 2002

CA025567, Develop and Implement a Modification Request to Fix the HELB Issue Identified in OD 98-0164, June 12, 2002

CA025568, Review and Revise the 14 Open Operability Determinations to Ensure Adequate Justification is Provided for Those Issues That Are Older Than 18 Months, June 12, 2002

CA025569, Factor Lessons Learned From This Root Cause Into the Fleet Procedure On Operability Determinations That Is In Development, June 12, 2002

CA025570, Revise NP 5.3.7, Operability Determinations to More Clearly Define the Meaning of "Earliest Available Opportunity," "First Available Opportunity," and "Not To Exceed the Next Refueling Outage," June 12, 2002

CA025571, Revise NP 7.1.6, Engineering Advisory Committee, With Appropriate Guidance on Reviewing ODs Related to GL 91-18, or Provide an Alternate Proceduralized Forum For Management Reviews of ODs With Explicit Review Criteria Related to GL 91-18, June 12, 2002

CA025572, Create and Implement Monthly Indicators as Directed by NP 5.37, Revision 8, and Present to Senior Management for Review on a Periodic Basis, June 12, 2002

CA026451, Per CARB Meeting of 9/17/2002 (NPM 2002-0498), Verify That a Previous CAP Was Written That Reviewed Outstanding ODs, September 24, 2002

Effectiveness Review EFR026452, Per CARB Meeting Minutes of 9/17/2002 (NPM 2002-0498), an Effectiveness Review is to be Performed on the Actions From RCE000051, "Failure to Establish Qualification Files For Equipment" in Mid-March 2003 by Engineering Programs, September 24, 2002

NP 5.3.7, Operability Determinations, Revisions 7, 8, and 9

NP 7.7.1, Environmental Qualification of Electrical Equipment, Revision 1

CAP023677, Massive Formation of Ice Has Collected on Cable Tray in Southwest Corner of Unit, March 22, 1997

CAP001548, North Circulating Water Pump House Manhole Does Not Have a Means to be Pumped, May 6, 1997

CAP018114, 350 MCM Cable May Be Too Small For the 240 ft Submerged Cable Run, October 4, 1997

CAP023960, Power Cables Submerged in Flooded Manholes, October 7, 1997

CAP008423, Circulating Water Pump 1P-030B Power Cable (1A12A) Conductor Failure, October 16, 1997

CAP008447, Power Cables (1A06A) Submerged in Flooded Manhole, October 21, 1997

CAP023997, Groundwater Leakage in Unit 2 Facade, October 27, 1997

CAP018286, Manhole Filling With Water, November 1, 1997

CAP028237, Derating Cable Ampacities for Fire Protection Provisions, December 19, 1997

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CAP019903, Intrusion Alarm Received on Manhole Cover, April 4, 1998

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CAP012212, Underground Cable Submerged in Water, June 22, 2000

CAP000215, Water Flow Into Through Conduits and Manholes, July 7, 2000

CAP000324, Cable Aging Issues, November 20, 2000

CAP029059, Medium Voltage Cables in Duct Packs in Flooding Water and Manholes Flooded, August 16, 2002

WO 0208378, Pump Electrical Manhole Pumps

CE007761, Significant Evaluation Report 97-06, PVC-Insulated Instrumentation and Control Wires, Closed January 1999

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LER 301/2002-02-00, Pressurizer Safety Valve Failed to Lift at Test Pressure, June 28, 2002

LER 301/2002-02-01, Pressurizer Safety Valve Failed to Lift at Test Pressure, October 28, 2002

CAP003109, RC-435 Failure to Lift, Cause, Reference CAP003020, April 30, 2002

Point Beach Calculation 2002-0030, Change In Core Damage Risk Associated With An Inoperable Primary Safety Valve, September 30, 2002

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RCE000055, Pressurizer Safety Valve Failed to Lift at Test Pressure, September 10, 2002

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LER 266/2002-001-00,Steam Generator Blowdown Valve Analysis As Not Able To Close Against Full Differential Pressure, October 15, 2002

CAP029065, SG Blowdown Valve 1MS-5959 May Not Close Against Full SG Pressure, August 16, 2002

CA026119, Document Resolution of CAP029065 Significance Level A, August 20, 2002

MRE000063, Perform a Maintenance Rule Evaluation per CAP029065 Significance Level A, in Accordance with NP 7.7.5, August 20, 2002

CA026120, Assess CAP029065 Significance Level A for Reportability, August 20, 2002

OTH 026507, This Tracks Acceptance of Level A RCE000188 by CARB, September 27, 2002

CAP029106, 10 CFR 50.72 Event Notification Contained Incorrect References, August 21, 2002

RCE000188, Perform a Root Cause Evaluation of CAP029065 per 09/27/02 Manager's Screen Meeting, September 27, 2002

ACE000971, Conduct an Apparent Cause Evaluation for This Issue in Accordance With NP 5.3.1, October 3, 2002

AOV Component Level Calculation, MS-05959 (Unit 1 and 2), Calculation No. 01109-C-015, Revision 0

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M-217, sheet 1; Auxiliary Feedwater System; May 25, 2002

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2002-0031; Change in Core Damage Risk Associated with a Fire Initiated by 1P29; Revision 1

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