July 25, 2002

Mr. M. Warner
Site Vice President
Kewaunee and Point Beach Nuclear Plants
Nuclear Management Company, LLC
6610 Nuclear Road
Two Rivers, WI 54241

SUBJECT: POINT BEACH NUCLEAR PLANT
NRC INTEGRATED INSPECTION REPORT 50-266/02-06; 50-301/02-06

Dear Mr. Warner:

On June 30, 2002, the U. S. Nuclear Regulatory Commission (NRC) completed an inspection at your Point Beach Nuclear Plant. The enclosed report documents the inspection findings which were discussed on June 24, 2002, with you and members of your staff.

The inspection examined activities conducted under your license as they relate to safety and 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. Specifically, this inspection was a routine review of plant activities by the resident and regional inspectors and a review of radiation protection, security, heat sink, and inservice inspection activities by regional inspectors.

Based on the results of this inspection, the inspectors identified one finding of very low safety significance (Green) and one other issue for which the safety significance was still to be determined. The issue still to be determined pertained to the use of hot-calibrated steam generator narrow range level instruments during cold plant conditions. This issue did not present an immediate safety concern and will be considered an Unresolved Item pending further risk assessment activities. A preliminary NRC review of the risk significance of the finding determined that it was at least of very low safety significance (Green) since the ability to remove reactor decay heat during shutdown plant conditions was affected. Finally, one violation of very low safety significance (Green) was identified by your staff and is listed in Section 4OA7 of this report.

The NRC has increased security requirements at Point Beach in response to terrorist acts on September 11, 2001. Although the NRC is not aware of any specific threat against nuclear facilities, the NRC issued an Order and several threat advisories to commercial power reactors to strengthen licensees' capabilities and readiness to respond to a potential attack. The NRC continues to monitor overall security controls and will issue temporary instructions in the near future to verify by inspection the licensee's compliance with the Order and current security regulations.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if you provide one, will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (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).

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Sincerely,

/RA/

Roger D. Lanksbury, Chief
Projects Branch 5
Division of Reactor Projects

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

Enclosure: Inspection Report 50-266/02-06;
50-301/02-06

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-266; 50-301
License Nos:	DPR-24; DPR-27
Report No:	50-266/02-06; 50-301/02-06
Licensee:	Nuclear Management Company, LLC
Facility:	Point Beach Nuclear Plant, Units 1 & 2
Location:	6610 Nuclear Road Two Rivers, WI 54241
Dates:	April 1, 2002, through June 30, 2002
Inspectors:	P. Krohn, Senior Resident Inspector, Point Beach J. Lara, Senior Resident Inspector, Kewaunee M. Morris, Resident Inspector, Point Beach Z. Dunham, Resident Inspector, Kewaunee R. Schmitt, Radiation Specialist D. Jones, Reactor Engineer P. Peterson, Senior Operations Examiner T. Madeda, Physical Security Inspector J. Maynen, Observer/Trainee G. O'Dwyer, Reactor Inspector M. Kunowski, Project Engineer R. Winter, Reactor Engineer
Approved by:	Roger D. Lanksbury, Chief Projects Branch 5 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000266-02-06, IR 05000301-02-06; Nuclear Management Company, LLC; on April 1 - June 30, 2002; Point Beach Nuclear Plant, Units 1 & 2. Operability Evaluations, Refueling and Outage Activities, Surveillance Testing.

This report covers a 13-week period and was conducted by resident and regional projects, radiation specialist, security, reactor, and operator licensing inspectors. The inspectors identified one finding of at least very low safety significance (Green) that, pending further regulatory review, was considered an Unresolved Item. The inspectors also identified another finding of very low safety significance (Green) concerning the use a dedicated operator to restore a mitigating systems to service. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, “Significance Determination Process.” Findings for which the Significance Determination Process (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, and can be found at the Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/assess/index.html.

A. Inspector-Identified Findings

Cornerstone: Mitigating Systems

- To Be Determined. Unit 2. On April 26, 2002, during the Unit 2 U2R25 refueling outage, the inspectors identified that the steam generator narrow range level detectors, calibrated for normal, hot steam generator operating conditions were being used during cold plant conditions to satisfy Technical Specification surveillance requirements. This resulted in a non-conservative density error affecting narrow range level indication such that at steam generator temperatures of 200 degrees Fahrenheit (°F), the actual water level was approximately 4.0 percent lower (closer to the top of the U-tube bundle) than indicated. During certain accidents, this error could result in uncovering the secondary side of the top of the steam generator U-tubes. This issue did not present an immediate safety concern and was considered an Unresolved Item pending further regulatory review of the risk aspects of the density compensation error.

  The inspectors concluded that the failure to account for the impact of varying water density differences on the steam generator narrow range level detector when transitioning from hot to cold plant conditions was more than minor and affected the capability of the steam generators, a mitigating system for a shutdown unit, to remove reactor decay heat. (Sections 1R20.1 and 4OA2.1).

- Green. The inspectors identified a finding of very low safety significance as a result of the licensee providing procedural guidance to a dedicated operator to perform ancillary duties away from the designated duty station, such that the intended functions could not be performed within the bounding time limits of the design basis analysis.

The inspectors determined that the issue was of more than minor significance since the issue affected the availability and capability of the G-03 emergency diesel generator, a mitigating system component, to respond to Unit 1 design basis events. Since the inspectors intervened and the dedicated operator did not perform ancillary duties away from the intended duty station such that the intended functions could not have been performed, the issue was determined not to represent a violation of NRC requirements. (Section 1R22.1)

B. Licensee-Identified Findings

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.

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Report Details

Summary of Plant Status
Unit 1 began the inspection period at full power and remained there until May 4, 2002, when power was reduced to 90 percent to support switchyard maintenance activities. Unit 1 returned to full power later the same day and remained there until May 30, when power was again reduced to 90 percent to support switchyard maintenance activities. Unit 1 returned to full power operations later the same day and remained there until June 15, when reactor power was reduced to 65 percent for turbine stop valve, atmospheric steam dump, condenser steam dump, crossover steam dump, and switchyard maintenance activities. Following crossover steam dump repairs, Unit 1 returned to full power operations on June 17 and remained there through the end of the inspection period.

Unit 2 began the inspection period at full power and remained there until April 11, 2002, when power was reduced to 99.6 percent due to a plant process computer system malfunction. Unit 2 was returned to full power operation later the same day and remained there until April 12, when the Unit was shutdown for the Unit 2 refueling outage (U2R25). The Unit 2 reactor was made critical on May 13 and synchronized to the electrical grid on May 14, 2002. Unit 2 returned to full power operations on May 17 and remained there until May 22, when reactor power was reduced to 94 percent for condenser steam dump testing. Unit 2 returned to full power operation later the same day and remained there until June 24, when power was reduced to 99.6 percent due to unreliable feedwater flow inputs to the reactor thermal power output calculation. Unit 2 resumed full power operations on June 28 and remained there through the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 High Wind/Tornado Preparations

a. Inspection Scope

During the week of May 20, 2002, the inspectors reviewed the facility design and the licensee’s procedures to evaluate the facility’s susceptibility to high winds and tornado weather conditions. Additionally, the inspectors walked down selected areas to evaluate plant buildings and equipment susceptible to high winds and tornados. The inspectors also reviewed Abnormal Operating Procedure, "Severe Weather Conditions," dated July 23, 2001, which prescribed station actions for severe weather conditions.

b. Findings

No findings of significance were identified.

.2 Hot Weather Preparations

a. Inspection Scope

During the week of May 20, 2002, the inspectors reviewed the facility design and the licensee's procedures to evaluate preparations for summertime high temperatures. Additionally, the inspectors walked down selected areas to evaluate plant equipment susceptible to high temperatures. The inspectors also evaluated the licensee's scheduling of the calibration of temperature switches for the G-01 emergency diesel generator (EDG) room ventilation fans. Calibration of the switches required that the fans be out-of-service, and if the outdoor temperature exceeded 80°F with the fans inoperable, then G-01 EDG would have to be declared out-of-service.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Instrument Air System Partial Walkdown

a. Inspection Scope

During the week of May 20, 2002, the inspectors performed a partial walkdown of the Units 1 and 2 instrument air system to verify proper system configuration. The inspectors used a licensee checklist (CL), piping and instrument diagrams, and system operating procedures during the walkdown to verify that the system was properly configured for full power operations.

b. Findings

No findings of significance were identified.

.2 Unit 2 Containment Spray System Partial Walkdown

a. Inspection Scope

During the week of May 20, 2002, the inspectors performed a partial system walkdown of the Unit 2 containment spray system to verify proper system configuration. The inspectors used licensee check lists CL 7A, "Safety Injection System Checklist Unit 2," and 2-TS-ECCS-001, "Safeguard Systems Valve and Lock Checklist (Monthly) Unit 2," during the walkdowns to verify that the system was properly configured. The inspectors also examined motor-operated valve and manually-operated valve material conditions to verify that the system was capable of performing design basis functions. The inspectors interviewed the system engineering staff concerning one valve with evidence of boric acid leaks. The inspectors also performed walkdowns in the control room to verify appropriate switch positions and valve configurations. Finally, the inspectors evaluated other elements such as material condition, housekeeping, and component labeling.

b. Findings

No findings of significance were identified.

.3 Service Water (SW) System Partial Walkdown

a. Inspection Scope

During the week of June 8, 2002, the inspectors performed a partial system walkdown of common portions of the SW system to verify proper system configuration. The inspectors used licensee CL 10B, “Service Water Safeguards Lineup,” Revision 52, during the walkdown to verify that the system was properly configured. The inspectors performed walkdowns in the primary auxiliary building, the EDG rooms, and the auxiliary feedwater (AFW) pump rooms to verify that switch, breaker, and valve configurations were correct and piping material condition was acceptable. During the walkdown, the inspectors also examined motor-operated and manually-operated valve material conditions to verify that the system was capable of performing design basis functions. Finally, the inspectors evaluated other elements such as material condition, housekeeping, and component labeling.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

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

- Fire Zone 151, Safety Injection (SI) Pump Room
- Fire Zone 142, Component Cooling Water (CCW) Pump Room
- Fire Zone 552, SW Pump Room
- Fire Zone 582, Oil Storage Room
- Fire Zone 272, Heating, Ventilation, and Air Conditioning Fan Room - Unit 1
- Fire Zone 273, Heating, Ventilation, and Air Conditioning Fan Room - Unit 2
- Fire Area A01E, Unit 2 Turbine Building Operating Floor
- Fire Area 104, Unit 1 1P-10A Residual Heat Removal (RHR) Pump Room
- Fire Area 105, Unit 1 1P-10B RHR Pump 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 toured the fire zones to verify that fire hoses, sprinklers, portable fire extinguishers, and fire detectors were installed at their designated locations, were in satisfactory physical condition, and were unobstructed. Additionally, passive features such as fire doors, fire dampers, and mechanical and electrical penetration seals were examined 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 Annual Review of Internal and External Flood Protection Measures

a. Inspection Scope

During the week of May 13, 2002, the inspectors reviewed internal and external flooding design bases documents, flooding mitigation equipment, and risk analyses to determine if existing configurations and mitigation plans were consistent with design requirements and risk analysis assumptions. The inspectors walked down the following areas to assess the overall readiness of flood protection equipment and barriers.

- Heating, Ventilation, and Air Conditioning Equipment Room (above the control room)
- Auxiliary Building (focusing on the containment building facade area and portions of the RHR pump room flood barrier configuration)
- EDG Rooms (G-01 and G-02)
- Instrument Air Compressor Room
- Turbine Building (auxiliary building secured access doors)
- AFW Pump Rooms
- Circulating Water Pump House Wave Barrier Locations
- Vital Switchgear and Battery Rooms

Emphasis was placed on the material condition of flood protection equipment, and the material condition and operational status of flood barriers used to mitigate flood damage or propagation. Flood protection features such as flood doors and door gaps, subsoil drains, and flood zone penetration seals were also inspected to verify that they were in satisfactory physical condition, unobstructed, and capable of providing an adequate flood barrier. Inspectors reviewed the licensee's normal and abnormal operating procedures, associated with flood identification and mitigation. Also, the inspectors reviewed annunciator response procedures associated with high sump level alarms and the associated lack of equipment calibration.

The inspectors reviewed several corrective action program documents, including an action request (AR) identified during the inspectors' plant walkdowns. Specifically, AR 3333, "Various Flooding Issues," concerning broken subsoil drain straps and flood door material condition deficiencies was reviewed. In addition, several other licensee-identified condition reports (CRs), still in open status, were also reviewed to determine the adequacy of the implemented and pending corrective actions.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

.1 Biennial Review of Heat Sink Performance

a. Inspection Scope

The inspector reviewed documents associated with testing, inspection, cleaning and performance trending of heat exchangers, primarily focusing on the Component Cooling Heat Exchanger HX-12A and the Unit 1 Residual Heat Removal Heat Exchanger PB1 HX-11A. These two heat exchangers were chosen based on their importance in supporting required safety functions as well as relatively high risk achievement worths in the plant specific risk assessment. Component Cooling Heat Exchanger HX-12A was also selected to evaluate the licensee's thermal performance testing methods. Waste Gas Heat Exchanger HX-48A-1 was originally included in the scope of this inspection based on a relatively high risk achievement worth; however, the licensee reassessed the risk achievement worth of the heat exchanger as relatively low so it was removed from the scope of the inspection. The inspector reviewed completed surveillance tests and associated calculations, and performed independent calculations to verify that these activities adequately ensured proper heat transfer. The inspector reviewed the documentation to confirm that the test or inspection methodology was consistent with accepted industry and scientific practices, based on review of heat transfer texts and Electrical Power Research Institute standards (EPRI NP-7552, Heat Exchanger Performance Monitoring Guidelines, December 1991; EPRI TR-107397, Service Water Heat Exchanger Testing Guidelines, March 1998).

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

The documents that were reviewed are listed at the end of the report. Also attached are the two information requests sent to the licensee in preparation for the inspection of this area: (1) the request for the inspection originally scheduled December 3-7, 2001, but postponed; and (2) the revised request for the inspection accomplished on June 10-14, 2002.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08)

a. Inspection Scope

The inspectors evaluated the implementation of the licensee’s ISI program for monitoring degradation of the reactor coolant system (RCS) boundary and the risk significant piping system boundaries. Specifically, the inspectors observed in-process liquid penetrant inspections of pressurizer pipe-to-reducer weld (CVC-02-AS-2001-29), swage reducer-to-valve weld (RC-03-PSF-2003-08A), pipe-to-swage reducer weld (RC-03-PSF-2003-08A), and magnetic particle inspection of feedwater pipe-to-nozzle weld (FW-16-FW-2002-18G) to verify that they were conducted in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code requirements.

The inspectors also reviewed ISI procedures and personnel and equipment certifications. The inspectors reviewed the NIS-2 forms for code repairs performed during the last Unit 2 outage (U2R24) to confirm that code requirements were met. In addition, the inspectors reviewed CRs concerning ISI issues to verify that an appropriate threshold for identifying issues had been established. The inspectors also evaluated the effectiveness of the corrective actions for identified issues. In addition, the inspectors reviewed the licensee’s operating experience review process to verify that operating experience was correctly assessed for applicability by the ISI group.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Resident Inspector Quarterly Review: Instrument Failure With Steam Release from Both Steam Generators

a. Inspection Scope

On May 23, 2002, the resident inspectors observed licensed operator training involving a steam leak on an 'A' steam generator sensing line followed by a reactor trip and depressurization of the 'B' steam generator due to a stuck open safety valve. The scenario focused on communications standards, peer checking, and peer-to-peer feedback. The inspectors evaluated crew performance for clarity and formality of communication; the ability to take timely action in the safe direction; the prioritizing, interpreting, and verifying of alarms; the correct use and implementation of procedures, including alarm response procedures; timely control board operation and manipulation, including high-risk operator actions; and group dynamics. The inspectors observed the post-scenario crew critique and reviewed the instructor's written observations to verify that areas for improvement had been identified and entered into performance development initiatives.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

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), CRs, ARs, (a)(1) corrective action plans, selected surveillance test procedures, and a sample of CRs to verify that the licensee was identifying issues related to the maintenance rule at an appropriate threshold and that corrective actions were appropriate. 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:

- Cable Spreading Room Heating and Ventilation System during the week of April 8, 2002
- 125-Volt Direct Current Electrical System during the week of May 6, 2002

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of plant risk, scheduling, configuration control, and performance of maintenance associated with planned and emergent work activities, to verify that scheduled and emergent work activities were adequately managed. In particular, the inspectors reviewed the licensee's program for conducting maintenance risk safety assessments to verify that the licensee's planning, risk management tools, and the assessment and management of on-line risk were adequate. The inspectors also reviewed licensee 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 the actions were accomplished when on-line risk was increased due to maintenance on risk-significant systems, structures, and components. The following specific activities were reviewed:

- The maintenance risk assessment for work planned for the week beginning May 12, 2002. This work included overhaul and surveillance testing of the

P-32E SW pump with the G-02 EDG out-of-service and transition of Unit 2 from the deterministic shutdown safety assessment (SSA) model to the quantitative on-line risk monitor during plant heat-up and startup activities.

- The maintenance risk assessment for work planned for the week beginning May 19, 2002. This work included risk-significant surveillance testing of the G-01 EDG, drilling into the basemat and subsequent testing to address a vibration problem associated with the generator-end of the G-02 EDG, and inspection and maintenance of the south SW header strainer.

- The maintenance risk assessment for work planned for the week beginning June 17, 2002. This work included calibration of the temperature switch for the G-01 EDG room ventilation system, repair and testing of the electric fire pump, and repair and testing of the turbine/moisture separator reheater crossover steam dump system.

- The maintenance risk assessment for work planned for the week beginning June 24, 2002. This work included 4.16 kilovolt (kV) undervoltage surveillance tests for Units 1 and 2, SI system maintenance, and a diesel fire pump engine inspection, repair, and post-maintenance test.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Reduced Charging Flow During a Postulated Fire Due to Lack of a Nitrogen Backup Supply

a. Inspection Scope

During the week of May 20, 2002, the inspectors reviewed Engineering Evaluation 2002-016, "MAAP [Modular Accident Analysis Program] Analysis to Support Reduced Charging Flow," to determine the transient behavior of the RCS in the event of an Appendix R fire scenario, assuming only 8 hours of single charging pump speed control was available. The issue was reported in Event Notification 38819 as an unanalyzed condition that had the ability to significantly degrade plant safety, since certain Appendix R scenarios required the availability of a single charging pump, operable at greater than minimal pump capacity, in order to meet the Appendix R performance goal of maintaining adequate RCS inventory without loss of pressurizer level indication.

The inspectors reviewed the licensee input and assumptions used in the transient analysis to verify the realism and accuracy of the analytical results. The inspectors examined the modeling of the reactor coolant pump (RCP) seal package failure during the Appendix R scenario as a series of small-diameter RCS breaks to verify that the approach remained bounding for the seal package characteristics predicted by the vendor. The inspectors compared the RCP seal package and the top-of-active fuel elevations to verify that, despite predicted voiding in the RCS, the core would remain covered and adequate core cooling would be maintained by a combination of steaming to containment and reflux cooling in the steam generator tubes. Finally, the inspectors reviewed core water temperature analytical results during the Appendix R scenario to verify that peak cladding temperatures remained well below the limits of 10 CFR Part 50.46.

b. Findings

Engineering Evaluation 2002-006 estimated the transient behavior of the RCS during a safe-shutdown Appendix R fire scenario with the normal cooling and safety systems unavailable. The evaluation included the loss of instrument air, RCP seal failures, disabling of charging pumps for the first 50 minutes of the scenario, and an initial charging capacity of 60 gallons per minute followed by a reduction to 18 gallons per minute 9 hours into the transient, due to loss of the back-up nitrogen supply. Reactor coolant pump seal leakage profiles provided by the seal vendor were simulated by varying the size of small break loss-of-coolant accidents as a function of RCS pressure.

The evaluation demonstrated that approximately 9 hours into the transient, when charging flow was reduced to 18 gallons per minute, pressurizer level and pressure would no longer be maintained. Approximately 11.5 hours into the transient, as RCS conditions approached those near the steam generator secondary saturation conditions, the evaluation demonstrated that RCS subcooling would be lost and voiding would begin to occur in the primary system. In addition, since the charging flow would be unable to keep up with the RCP seal break flow, RCS inventory would continue to be lost and the RCP seals would eventually begin to emit steam. Once the RCP seals were uncovered and the break flow became all steam, the charging flow would become sufficient to maintain RCS inventory near the RCP seal elevation. Venting of steam at the RCP seal elevation maintained approximately 11.0 feet of water over the top-of-active fuel in the reactor core. As RCS pressure would continue to decrease, the evaluation predicted that the reactor vessel would approach saturation conditions and bulk boiling would occur in the core. The engineering evaluation demonstrated that the water in the core would remain at approximately 570°F, provide a large margin to the peak cladding temperature limit of 10 CFR Part 50.46, and prevent core damage.

This issue was determined to be more than minor and affected the barrier integrity cornerstone objective since the lack of sufficient back-up nitrogen capacity for the charging pumps would, had a safe shutdown Appendix R fire scenario occurred, have resulted in loss of the RCP seals, an active component of the RCS boundary required for RCS functionality. The loss of the RCP seals would have led to voiding portions of the RCS primary system causing unintended boiling in the reactor core.

The inspectors used Manual Chapter 0609, “Significance Determination Process,” Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” regarding the mitigating systems and RCS barrier integrity and determined that:

- The finding did not result in fuel damage since back-up nitrogen supply was never required during an Appendix R safe shutdown scenario and engineering evaluations demonstrated that fuel temperatures would have remained well below regulatory had an Appendix R analyzed fire occurred;

- The finding did not represent an actual loss of the functionality of the RCS boundary since no Appendix R safe shutdown scenario occurred and RCS barrier integrity was never challenged through the loss of the RCP seals;
- The finding was not a design or qualification deficiency;
- The finding did not result in a loss of function of a single train of any mitigating systems for greater than its Technical Specifications (TS) allowed outage time and did not represent an actual loss of the safety function for any mitigating system;
- The finding did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours;
- The finding did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event in that the finding did not involve the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding or severe weather initiating event; and
- The finding did not involve the degradation of a fire protection barrier or loss of a safety function that contributed to external event initiated core damage accident sequences.

Therefore, the finding screened as Green and was of very low safety significance. This issue is dispositioned in Section 4OA7 of this report.

.2 Auxiliary Building High Energy Line Break (HELB) Analysis

a. Inspection Scope

During the week of April 29, 2002, the inspectors reviewed Operability Determination 98-0164, “Qualification of Electrical Equipment,” and AR 2976, “Problems with OD [Operability Determination] 98-0164 (PAB [Primary Auxiliary Building] HELB),” to determine if a CCW pump that was assumed idle when a PAB steam line break occurred, could subsequently be started with adverse conditions present in the PAB. Since the charging pumps were not credited during a HELB in the PAB, the inspectors concentrated on the CCW pumps, since they were required to maintain the RCP seals intact and prevent progression of the event to a small break loss-of-coolant accident. The inspectors compared the assumptions and conclusions in the operability determination against the Final Safety Analysis Report (FSAR) requirements to verify that components in the PAB would be able to meet design basis requirements. In addition, the inspectors reviewed the use of the simulator in determining plant response to a HELB to verify that plant response was accurately modeled and applied to the operability determination.

b. Findings

No findings of significance were identified.

.3 Unit 2 Containment Fan Coil Unit Reduced Flow Rate

a. Inspection Scope

During the week of May 20, 2002, the inspectors reviewed Operability Determination 01-1559, “Unit 2 Containment Fan Coil Unit Reduced Flow Rates,” to verify the containment fan coils remained capable of removing containment heat loads during design basis accidents and maintaining containment temperatures and pressures within design limits. The inspectors compared FSAR containment fan coil heat removal data against the reduced air flow characteristics in the operability determination to determine the effect on peak containment pressures. The inspectors considered the potential effects of higher peak containment pressures on the environmental qualification of structures, systems, and components inside containment, an item not addressed in the operability determination.

b. Findings

No findings of significance were identified.

.4 Common Cause Failure Analysis For Aborted G-02 EDG Extended Surveillance Test

a. Inspection Scope

During the week of June 10, 2002, the inspectors reviewed AR 28360, “G-02 Failure During the Performance of TS 82 Extended Run,” and AR 28420, “G-02 Run At Full KW [Kilowatt] Loading and Above Full Load KVAR [Kilovolt-Amperes Reactive] On Two Separate Occasions,” to determine the common mode failure applicability to other EDGs. The inspectors compared the EDG voltage regulator circuit designs and observed licensee troubleshooting efforts to verify that common mode failure concerns did not apply to the other EDGs. The inspectors also conducted reviews to verify that surveillance testing of the G-01 EDG with a similar circuit design was performed to ensure operability of the Unit 1, 'A' train EDG. When the cause of the G-02 surveillance failure was determined to be a tripped generator field excitation breaker, the inspectors reviewed the manufacturer's circuit breaker information to understand if the breaker had operated as expected and per design. The inspectors reviewed the licensee's conclusion that the cause of the excitation breaker trip was a low-reading Volt-Amperes Reactive meter in the control room resulting in the EDG being overexcited to achieve the Kilovolt-Amperes Reactive indication required by the G-02 routine inspection test. The inspectors considered the impact of the EDG over-excitation on design basis EDG accident response to ensure that all emergency core cooling system (ECCS) equipment would still have operated as expected. Finally, the inspectors considered the over-excitation effects on increased generator heat loads and the resultant effects on winding insulation resistance and life.

b. Findings

No findings of significance were identified.

.5 Relaxation of Reactor Power Limits for an Inoperable Crossover Steam Dump System

a. Inspection Scope

The inspectors reviewed the licensee's relaxation of previous procedural constraints on reactor power when the turbine/moisture separator reheater crossover steam dump system was inoperable. This system was one of several turbine overspeed protection systems at Point Beach and was declared inoperable on June 16 due to a problem with one of the four valves during testing on Unit 1. The basis for the licensee's revised position was an analysis done several years ago by the turbine vendor that concluded that the crossover steam dump system at Point Beach was not needed for overspeed protection.

b. Findings

No findings of significance were identified.

.6 Unit 1 Turbine-Driven Auxiliary Feedwater Pump Outboard Bearing Degradation

a. Inspection Scope

During the week of June 10 and 24, 2002, the inspectors reviewed Operability Determination OPR-000019, "1P-29 Turbine-Driven Aux Feed Pump Outboard Bearing Degradation," to verify that the pump remained capable of performing its intended safety function. The inspectors reviewed a May 2002 ferrogram oil analysis report to determine the degree of bearing wear that had occurred and to estimate the rate of wear progression since the last oil sample taken in November 2001. The inspectors considered the wear particle sizes, the dimensions of the lubrication hydrodynamic gaps, and the metallurgical components of the oil analysis to determine the degree to which the turbine journal bearing babbitt material had been affected by the wear particles found in the oil sample. The inspectors also reviewed turbine vibration and acceleration measurements to estimate whether bearing wear was in an early or advanced stage of development. Finally, the inspectors reviewed licensee plans and WOs to change and re-sample the turbine bearing oil to understand licensee actions for monitoring bearing performance.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (OWAs) (71111.16)

.1 Spurious Alarms During Start Of Safeguards Pumps

a. Inspection Scope

The inspectors reviewed OWA 0-00R-004 to understand potential effects on plant operations caused by operators responding to spurious alarms received during the start of Unit 1 and Unit 2 safeguards pumps. The inspectors interviewed engineering personnel, reviewed the pending modification, and examined the developed work package to evaluate the adequacy of planned licensee actions. The workaround concerned the start of large Unit 1 and Unit 2 motors affecting the 480-volt supply to the battery chargers which, in turn, caused DC bus perturbations. The inspectors reviewed the proposed changes to determine if the incorporation of alarm circuit time delay relays would allow the DC bus to return to a normal levels following the starting a large motor and prevent spurious alarms. Finally, the inspectors reviewed diagrams to ascertain that the modification would not adversely interfere with the safety function of the DC charging system or the ground detection system.

b. Findings

No findings of significance were identified.

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

.1 Gas Turbine Generator G05 Testing

a. Inspection Scope

The inspectors reviewed PMT activities associated with the G-05 gas turbine generator, which had been taken out-of-service on May 21, 2002 to remove residual fuel oil from the generator battery cells. The oil had been sprayed on the battery when a relief valve lifted during previous generator operations. Although the bulk of the oil had been cleaned up after the relief valve lifted, the battery manufacturer recommended more extensive cleaning to prevent long-term degradation of the plastic battery cell cases from traces of fuel oil. After the cleanup, the licensee conducted Periodic Check 29, “Monthly Gas Turbine and Auxiliary Diesel Load Test,” Revision 34, for the PMT. The licensee chose to perform the more extensive monthly test, rather than just a check of battery parameters, because of previous instances where emergent equipment problems occurred after the generator had been out-of-service for an extended period of time. The inspectors reviewed WO 0205569, under which the battery cleanup work had been done, and the records associated with the completed Periodic Check (PC) 29 surveillance test, to verify that the test was adequate for the scope of the maintenance that had been performed and that the test data were complete, appropriately verified, and met the requirements of the test procedure.

b. Findings

No findings of significance were identified.

.2 Replacement of 2RC-00427, Unit 2 RCS 'B' Loop Cold Leg to Chemical and Volume Control System Letdown Isolation Valve

a. Inspection Scope

The inspectors observed portions of freeze seal operations and the PMT associated with replacement of 2RC-427, 'B' RCS Loop Cold Leg to Chemical and Volume Control system letdown isolation valve, during the Unit 2 refueling outage to ensure the integrity of RCS pressure boundary material. Selected RCS boundary welds were inspected to verify proper fillet dimensions, lack of porosity due to moisture intrusion, and good pipe-to-pipe alignment. Since 2RC-00427 was unisolable from the reactor vessel and fuel was loaded in the core during the valve replacement, the inspectors walked down portions of the freeze seal to verify that system pressures, ambient temperatures, fluid temperatures, pipe geometry, pipe material, pipe restraints, and pipe weld limitations were within specified parameters. The inspectors reviewed the piping classification and original construction code requirements associated with 2RC-00427 to verify that the non-destructive examinations performed as part of the PMT met applicable Code requirements. The inspectors reviewed the completed WO and final non-destructive examination records associated with the valve replacement to verify that all visual, dye penetrant, and ultrasonic examinations had been completed and recordable indications properly dispostioned.

Finally, the inspectors reviewed Corrective Action Process (CAP) 028627, "Documentation Deficiencies Identified In a Completed (Reviewed) Work Order," which was initiated as a result of this inspection activity and discussed missed documentation concerning post-maintenance visual and dye penetrant testing results.

b. Findings

No findings of significance were identified.

.3 Repair and Testing of the Electric Fire Pump, P-35A

a. Inspection Scope

The inspectors reviewed the repair and subsequent PMT of the electric fire pump, P-35A. The pump had been taken out-of-service in mid-June for replacement of the upper end bell, an oil change, replacement of its 480-volt breaker, and repacking.

b. Findings

No findings of significance were identified.

.4 Repair and Testing of the Spent Fuel Pool (SFP) System

a. Inspection Scope

The inspectors reviewed the repair and PMT of the spent fuel system. The repairs included cleaning and eddy current testing of, and plugging of a defective tube in the HX-13A SFP heat exchanger, and replacement of the 2-inch SFP return to SFP Valve, SF-28.

b. Findings

No findings of significance were identified.

.5 Diesel-Driven Fire Pump 3-Year Maintenance Overhaul

a. Inspection Scope

The inspectors observed portions of the overhaul activities associated with the diesel-driven fire pump, P-35B, to gain insights into the adequacy of the PMT activities. The inspectors also reviewed design basis requirements and observed portions of the tests performed in accordance with Point Beach 0-PT-FP-002, “Monthly Diesel Engine-Driven Fire Pump Functional Test,” Revision 1, to verify that the fire pump was capable of performing its design functions. The inspectors reviewed the completed test documentation to verify that all acceptance criteria had been met.

b. Findings

No findings of significance were identified.

.6 Unit 1 CCW Expansion Tank Level Transmitter Replacement

a. Inspection Scope

During the week of June 24, 2002, the inspectors observed portions of the replacement of level transmitter 1LT-618, CCW Surge Tank Level Transmitter, and reviewed WO 9949340 to verify that remote control room indication of leaks into or out of the CCW system was maintained. The inspectors performed a walkdown of the level transmitter and associated connections following the transmitter replacement to verify that the instrument had been properly returned to service, was leak tight, and remained capable of providing remote alarms to the control room. The inspectors also reviewed the use of a temporary tygon tube, monitored locally, for surge tank level measurements to verify that the proximity of the actual level to alarm setpoints had been understood by auxiliary operators.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

.1 Use of Steam Generator Narrow Range Level Detector During Cold Shutdown

a. Inspection Scope

The inspectors reviewed the use of the steam generator narrow range level detector in Mode 3 (hot standby, RCS >350°F), Mode 4 (hot shutdown, RCS between 200°F and 350°F), and Mode 5 (cold shutdown, RCS <200°F) to determine if the effect of water density changes with decreasing plant temperatures had been considered in detector parametric uncertainty analyses. The inspectors interviewed selected engineering and operations personnel and performed independent calculations to determine the magnitude of the density error associated with using the hot-calibrated steam generator narrow range water level detector during cold plant conditions. The inspectors reviewed setpoint and shutdown emergency procedure background documents to determine the intent of establishing a 29 percent steam generator narrow range level setpoint during cold plant conditions. The inspectors also reviewed operator logs and selected surveillance, inservice, and infrequently performed test evolution procedures to determine the extent to which the steam generator narrow range level detector density correction errors existed in plant procedures.

The inspectors reviewed plant specific steam generator construction drawings and combined detector readability, loop uncertainty, and density errors to determine whether, under certain plant conditions, the top of the steam generator U-tubes could become uncovered while the steam generator was being credited as an alternate means of reactor decay heat removal. The inspectors performed independent calculations to estimate the amount of U-tube heat transfer surface area lost on the secondary side of the steam generators as a result of the combined level detector errors causing the upper portions of the U-tubes to become uncovered. The inspectors reviewed engineering evaluations, temporary procedure changes, procedure feedback forms, and safety evaluation screenings to ensure the licensee had identified all the vulnerabilities associated with the steam generator narrow range level detector density compensation issue. To evaluate the effectiveness of licensee internal communications, the inspectors reviewed licensee actions following the first inspector notification of the issue on April 30, 2002, and the time before all procedure changes were identified on May 28, 2002.

b. <u>Findings</u>

The inspectors identified an Unresolved Item of at least very low safety significance concerning the failure to account for the impact of varying water density differences on the steam generator narrow range level detector variable leg when transitioning from hot to cold plant conditions. Specifically, safety-related shutdown emergency procedures contained operator instructions that could have caused the top of the steam generator U-tubes to become uncovered, thereby affecting the ability of the steam generators to function as a heat sink for removing reactor decay heat.

<u>Description</u>

On April 26, 2002, during the Unit 2 refueling outage (U2R25) the inspectors determined that the steam generator narrow range level detectors, calibrated for normal, hot steam generator operating conditions of 521°F and 821 pounds per square inch absolute pressure, were being used during cold plant conditions to satisfy TS surveillance requirements 3.4.5.2, 3.4.6.2, and 3.4.7.2. The inspectors' observation was that as steam generator water temperatures decreased (and level detector variable leg water densities increased) during a plant shutdown and cooldown, the difference between the narrow range indicated and actual water level increased in the non-conservative direction. At 200°F, this unaccounted density error resulted in a condition where the actual water level was approximately 4.0 percent lower (closer to the top of the U-tube bundle) than indicated.

Technical Specification surveillance requirements 3.4.5.2 and 3.4.6.2 required that once per 12 hours in Modes 3 and 4 the steam generator secondary side water level be verified greater than or equal to 30 percent narrow range for the required RCS loops being relied upon for decay heat removal. The applicable TS bases sections stated that if the water level was less than 30 percent, the U-tubes might become uncovered and the associated loop might not be able capable of providing a heat sink for removal of reactor decay heat. Similarly, TS 3.4.7.2 required that once per 12 hours in Mode 5 water level be verified greater than or equal to 30 percent narrow range in the required steam generator. The applicable TS bases section stated that a steam generator was operable when the secondary side narrow range water level was greater than or equal to 30 percent since this level ensured an alternate method of decay heat removal via natural circulation in the event a second RHR loop was not operable.

The inspectors reviewed steam generator construction drawings and determined that the actual top occurred at 25.1 percent narrow range for the Unit 1 Model 44F steam generator U-tube bundle and at 25.3 percent narrow range for the Unit 2 Model D47 steam generators. In addition, the inspectors reviewed licensee setpoint verification program calculations PBNP-IC-25, "Steam Generator Narrow Range Level Instrument Uncertainty and Setpoint Calculation" and PBNP-IC-26, "Steam Generator Narrow Range Water Level Scaling Calculation," which discussed a 1 percent readability and 2.55 percent (rounded to 3 percent) total loop uncertainty error in the negative direction associated with the narrow range level instruments. The inspectors noted that these setpoint calculations had only been performed for normal operating and adverse containment conditions. Neither the calculations or the associated engineering evaluations accounted for the effects of increasing level detector variable leg water densities as steam generator water temperatures decreased during a plant shutdown and cooldown. Interviews with engineering and instrumentation and control personnel revealed that the density affect accounted for an approximate 2.2 percent non-conservative level deviation at 350 °F and an approximate 4.0 percent non-conservative level deviation at 200 °F.

To understand the bounding aspects of the density error, the inspectors considered the linear sum of the readability (1 percent), loop uncertainty (2.6 percent), and density errors (4.0 percent) that would impact the steam generator level detector in the negative direction at 200°F. Specifically, the inspectors considered the worst case, cumulative affect of the errors on two parts of safety-related Shutdown Emergency Procedure (SEP) 3.0, "Loss of All AC [Alternating Current] Power to a Shutdown Unit - Unit 1," Revision 12, and SEP 3.0, "Loss of All AC Power to a Shutdown Unit - Unit 2," Revision 13. Shutdown Emergency Procedure 3.0 provided direction for a loss of all alternating current power to a shutdown unit while the SI accumulators were isolated. In the first part of SEP 3.0, Step 5.b directed control room operators to check for at least one steam generator capable of being filled to greater than 29 percent narrow range (51 percent for adverse containment conditions). The background document for SEP 3.0, Step 5 stated that it was not necessary for the steam generator to be completely intact to consider it available as a secondary heat sink. Rather, if the U-tubes were intact and there was an available means to add water, the steam generator would remove decay heat. In the second part of SEP 3.0, Step 8.b directed control room operators to check at least one steam generator greater than 29 percent narrow range level (51 percent for adverse containment conditions). The background document for SEP 3.0, Step 8, stated that if the steam generator was to be used as a secondary heat sink, the steam generator U-tubes must remain covered to maintain natural circulation.

The inspectors determined that the linear sum of the worst case steam generator level detector errors in the negative direction at 200°F was 7.6 percent (1 percent + 2.6 percent + 4.0 percent = 7.6 percent). Applying this error to the 29 percent narrow range level guidance provided to control room operators in SEP 3.0, Steps 5.b and 8.b meant that the actual level in the steam generators could be 21.4 percent (29 percent minus 7.6 percent = 21.4 percent). For Unit 1 with the top of the U-tubes at 25.1 percent narrow range, this meant that a portion of the top of the U-tubes equivalent to 3.7 percent (25.1 minus 21.4) of the steam generator narrow range level detector 100 percent span could be uncovered. The 3.7 percent narrow range translated into the potential to uncover 7.6 inches of the top of the Unit 1 steam generator U-tubes. Using approximations from Unit 2 steam generator vendor drawings, this resulted in the potential uncovering of at least some part of 220 of 3214 tubes or about 6.9 percent of the U-tubes in Unit 1 steam generators. The inspectors estimated that uncovering the top 7.6 inches of the U-tubes would result in a loss of approximately 1 percent of the heat transfer area associated with the affected Unit 1 steam generator.

For Unit 2 with the top of the U-tubes at 25.3 percent narrow range, summing the worst case errors meant that a portion of the top of the U-tubes equivalent to 3.9 percent (25.3 minus 21.4) of the steam generator narrow range level detector 100 percent span could be uncovered. The 3.9 percent narrow range translated into the potential to uncover 8 inches of the top of the U-tubes in the Unit 2 steam generators. Using vendor steam generator drawings, this resulted in the potential uncovering of at least some part of 247 of 3499 tubes or about 7 percent of the U-tubes in Unit 2 steam generators. The inspectors estimated that uncovering the top 8 inches of the U-tubes in a steam generator would result in a loss of approximately 1 percent of the heat transfer area associated with the affected steam generator.

The inspectors also considered the sum of the readability, loop uncertainty, and density errors using the 'square root of the sum of the squares' (SRSS) methodology. The SRSS methodology represented a combination of statistical and algebraic methods that combined random and independent uncertainties with non-random or bias errors. Using the SRSS methodology, the readability and loop uncertainty errors were considered random and independent variables taken to act in the negative, non-conservative direction. The density error was treated as a bias with a known sign, acting in a specific direction, and known to contribute a fixed 4 percent uncertainty in the negative direction. The result of the SRSS methodology provided a 6.7 percent combined error that did not change the effect of uncovering a portion of the top of the steam generator U-tubes.

Analysis

The inspectors assessed this issue using NRC Inspection Manual Chapter 0609, "Significance Determination Process," Appendix G, issued February 27, 2001. The inspectors concluded that the failure to account for the impact of varying water density differences on the steam generator narrow range level detector when transitioning from hot to cold plant conditions had a credible affect on safety since the ability of the steam generators to remove reactor decay heat was affected. Specifically, safety-related shutdown emergency procedures contained operator instructions that could have caused the top of the steam generator U-tubes to become uncovered, thereby affecting the ability of the steam generators to function as a heat sink for removing reactor decay heat.

The inspectors reviewed licensing basis requirements and determined that prior to November 2001, TSs contained no steam generator narrow range water level requirements in Modes 3, 4, or 5 to ensure steam generator availability as a heat sink to remove reactor decay heat. Following the transition to Improved TSs at Point Beach during November 2001, however, TS surveillance requirements 3.4.5.2, 3.4.6.2, and 3.4.7.2 were added requiring that steam generator narrow range level be greater than or equal to 30 percent to verify steam generator operability as a heat sink to remove reactor decay heat. In the time period following November 2001, to the end of this report period, Unit 1 had not entered Mode 3, 4, or 5. Unit 2, however, completed a refueling outage between April 12 and May 14, 2002.

To understand the impact of the density compensation error on plant risk, the inspectors reviewed those portions of the refueling outage where the steam generators had been credited as an alternate method of reactor decay heat removal. These periods were then applied to the applicable Significance Determination Process, Phase 1, Appendix G Screening worksheet. Two periods applicable to the Phase 1 worksheets were identified.

During the first period near the beginning of the outage, from April 14 at 4:30 p.m. to April 15, 2002, at 4:45 p.m. (approximately 24 hours), the steam generators were credited as an alternate means of decay heat removal while Unit 2 was in Mode 5 (cold shutdown), the RCS was intact, the reactor coolant loops were full, inventory was maintained in the pressurizer, and time-to-boil in the core was less than 2 hours. The first period was a condition specifically identified in the second of four Appendix G pressurized water reactor Phase 1 screening worksheets, “PWR [Pressurized Water Reactor] Cold Shutdown Operation, RCS Closed and Steam Generators Available for DHR [Decay Heat Removal] Removal (Loops Filled and Inventory in Pressurizer, Time to Boiling Less Than 2 Hours).”

During the second period, near the end of the outage from May 4 at 1:00 p.m. to May 10, 2002, at 2:30 a.m. (approximately 132 hours), the steam generators were credited as an alternate means of decay heat removal while Unit 2 was in Mode 5 (cold shutdown), time-to-boil was greater than 2 hours, and inventory was maintained in the pressurizer. The second period was a condition specifically identified in the fourth of four Appendix G pressurized water reactor Phase 1 screening worksheets, “PWR Refueling Operation RCS Level > 23' Or PWR Shutdown Operation With Time to Boil > 2 Hours and Inventory in the Pressurizer.”

Both time periods affected Section I.B(1), “Core Heat Removal Guidelines, Training/Procedures,” of the applicable Appendix G Phase 1 worksheets, in that, when the steam generators were relied upon as an alternate means of reactor decay heat removal, safety-related SEP 3.0, Steps 5b and 8b contained inadequate guidance to ensure that the top of the secondary side of the U-tubes remained covered with water during a loss of all AC power to a shutdown Unit. The second worksheet indicated that findings which degraded the licensee's ability to establish an alternate core cooling path if decay heat removal could not be re-established required a Phase 2 SDP analysis. The fourth worksheet indicated that findings which affected procedures for normal and abnormal decay heat removal operation were characterized as having very low safety significance (Green).

Enforcement

The issue of failing to account for the impact of varying water density differences on the steam generator narrow range level detector variable leg when transitioning from hot to cold plant conditions did not present an immediate safety concern and is being treated as one technical issue with two applicable time periods. In accordance with Inspection Manual Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process," Section I, "Guidance," paragraph entitled "Finding Requiring Quantitative Assessment," the finding associated with the first time period (April 14, 2002, at 4:30 p.m. to April 15, 2002, at 4:45 p.m.) is being forwarded to the Region III Senior Reactor Analyst for quantitative risk assessment. The finding associated with the second time period (May 4, 2002, at 1:00 p.m. to May 10, 2002, at 2:30 a.m.) was characterized as having very low safety significance (Green) during the Phase 1 SDP screening process. However, since one technical issue was common to both time periods and the Senior Risk Analyst had not yet completed the quantitative risk assessment at the end of the inspection period, the safety significance of the issue is To Be Determined and the issue will be considered an Unresolved Item (URI) pending completion of the quantitative risk assessment activities (URI 50-301/02-06-01).

.2 Review of Planned Outage Activities, Schedule, and Shutdown Safety Assessment (SSA)

a. Inspection Scope

Prior to commencement of the Unit 2 U2R25 refueling outage, the inspectors reviewed the licensee's planned outage activities and scheduling, SSA, FSAR, TSs, and system configuration controls to evaluate the adequacy of the SSA. The SSA documented a deterministic evaluation of plant risk in the areas of reactivity, core cooling, power availability, containment, inventory, RCS integrity, and SFP cooling. Relative risk was determined by the licensee based on plant configuration and the redundancy of available systems and components for each day of the outage. Inspection attributes included verifying that the licensee considered measures such as establishing compensatory actions, minimizing the duration of the activity, and obtaining appropriate onsite review committee approval. Where specific components with dual unit, cross-tie capability were rendered unavailable during integrated SI tests, the inspectors evaluated the effect on Unit 1, which was operating at full power. In addition, the inspectors reviewed two orange risk configurations concerning containment integrity on Days 4 and 6 of the outage when the containment equipment hatch was removed and either the RCS was not intact or pressurizer level was below 5 percent. The inspectors reviewed contingency plans and selected equipment for adequacy and interviewed personnel to verify that they were available to perform designated tasks.

b. Findings

No findings of significance were identified.

.3 Unit 2 Shutdown, RCS Cooldown, and Transition to RHR Cooling

a. Inspection Scope

The inspectors observed portions of the Unit 2 down power and RCS cooldown to verify that the licensee was controlling the RCS in accordance with operating procedures. The inspectors also conducted reviews to verify that the cooldown rate did not exceed the TS limitations. Once conditions were met, the inspectors observed the transition to RHR cooling and performed walkdowns to verify that the RHR and CCW systems were adequately removing reactor decay heat. Additionally, the inspectors toured containment to identify level instruments which were to be used in draining down the RCS to 6 inches below the reactor vessel flange. Once the instruments were identified, the inspectors checked for proper level instrument configurations to ensure that reactor vessel level would be accurately indicated. Finally, the inspectors reviewed AR 2843, “TSAC [Technical Specification Action Condition] Entry in Mode 4 for RCS Loop Inoperable,” which was initiated when the 'A' RCP was voluntarily removed from service during the cooldown requiring an entry into TS Action Condition 3.4.5.A for one RCS loop being inoperable.

b. Findings

No findings of significance were identified.

.4 Review of Selected U2R25 Refueling and Outage Activities

a. Inspection Scope

The inspectors observed work activities associated with the Unit 2 refueling outage (U2R25) which began on April 13 and ended on May 14, 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 TSs. The inspectors also verified compliance with commitments made during licensee 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 lift and set
- adequate reactor vessel level and temperature instrumentation during reduced inventory
- reactivity monitoring of shutdown plant conditions, including establishment of source range nuclear instrument channel check criteria

- monitoring and verification of nuclear instrument operability during core alterations
- fuel handling activities during core reload
- review of boron concentration sampling results, source range nuclear instrumentation system operability, containment closure capability, and refueling cavity water levels and clarity during fuel handling activities
- walkdowns of the RHR system during reduced inventory to verify decay heat removal capabilities
- verification of correct danger tag isolation boundaries and activities for the 2A06 safeguards bus and 2X03 high voltage auxiliary transformer maintenance activities
- walkdowns of emergency alternating current electrical power distribution systems during electrical maintenance
- walkdowns and inspection of 2A06 safeguards bus during preventative maintenance and cleaning activities
- walkdowns of the SFP cooling system after all nuclear fuel had been offloaded from the reactor to the SFP
- walkdowns of selected shutdown inventory addition makeup paths
- walkdowns of RCS boundary integrity prior to increasing reactor vessel inventory
- a review of the effect of switchyard maintenance activities on continuity of power to safeguards buses relied upon to maintain operability of RHR systems
- walkdowns to verify that all debris which could inhibit mitigating the effects of a design basis accident were removed from the primary containment
- a review of the U2R25 containment coatings assessment to verify that degraded coatings observed on the wall of the 'B' steam generator cubicle had been considered in design basis accident containment sump recirculation transport analyses
- 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 CLs
- a review of the core reload safety evaluation, initial criticality, and low power physics testing data.

Finally, the inspectors reviewed AR 3011, “Valves Found Out of Position,” which was initiated as a result of this inspection activity and discussed SFP skimmer pump suction filter pressure indicator isolation valves that were found closed despite seismic analyses in February 2000 that had determined that they should remain open for continuous filter differential pressure monitoring, a parameter described in Section 9.9 of the FSAR.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Unit 2 ‘B’ Train ECCS Integrated SI Test

a. Inspection Scope

The inspectors observed integrated SI system testing in accordance with Operations Refueling Test (ORT) 3B, “Safety Injection Actuation With Loss of Engineered Safeguards AC Power (Train B) Unit 2,” on April 15, 2002, to determine the ability of Unit 2 safety-related equipment to respond to a design basis accident. The inspectors also reviewed Safety Evaluation 2002-0148, “ORT-3B Safety Injection Actuation With Loss of Engineered Safeguards AC Power (Train B),” to evaluate the use of a dedicated operator to recover and align the G-01 EDG to support a Unit 1 design basis event. Extended observations were performed from the control room to observe engineering safeguards equipment response. The inspectors observed ECCS load sequencing, shedding, and restoration to verify that Unit 2, 'B' train ECCS equipment was capable of performing the intended design function.

The inspectors reviewed pre-test equipment alignments and plant conditions prior to starting the test to verify proper system configurations. Communication practices, control room decorum, receipt of expected alarms and warning lights, supervisory control, procedure adherence, and the interface between test and on-shift licensed personnel were observed. The inspectors observed G-04 loading, frequency, voltage, and start times to verify that the EDG was capable of satisfying design basis requirements. The inspectors observed the crew response to degraded grid conditions during the refueling test to verify that conservative decisions were made relative to maintaining both Units 1 and 2 in stable configurations. The inspectors reviewed the completed test documentation to verify that all equipment acceptance criteria had been met and all equipment remained capable of performing the intended safety function.

b. Findings

The inspectors identified a finding of very low safety significance (Green) concerning ORT 3B, “Safety Injection Actuation With Loss of Engineered Safeguards AC [Alternating Current] (Train B),” Revision 33, which directed a dedicated operator to perform duties away from the Unit 1, 'B' train EDG, G-03, such that the intended functions could not be performed within the bounding time limits of the Unit 1 large break loss-of-coolant accident design basis.

Description

During U2R25, ORT 3B tested the 'B' Train of engineered safeguards equipment and the ability of the associated G-03 (Unit 1, 'B' Train EDG) and G-04 (Unit 2, 'B' Train EDG) EDGs to respond to design basis events. To allow testing of only one diesel at a time and to prevent a diesel from starting and running unloaded for an extended period of time, the refueling test directed disabling of the EDG not being tested during portions of the test on the remaining EDG. For instance, during Step 5.4, “Loss of AC Followed By Automatic Safety Injection With G-04,” G-03 was disabled.

On April 15, 2002, Unit 2 was in cold shutdown for U2R25 and Unit 1 was at full power. The Unit 1 risk assessment indicated that with G-02 (Unit 2, 'A' train EDG) having been previously taken out-of-service due to high vibrations and G-03 (Unit 1, 'B' Train EDG) and G-04 (Unit 2, 'B' Train EDG) removed from service for ORT 3B testing, Unit 1 would be in a risk configuration that was approximately 23 times the zero maintenance core damage frequency risk level. In accordance with licensee Nuclear Plant Procedure (NP) 10.3.7, “On-Line Safety Assessment,” Revision 6, this risk level was considered a 'Red' risk condition. To reduce the Unit 1 risk profile, the licensee performed Safety Evaluation 2002-0148, “ORT 3B Safety Injection Actuation With Loss of Engineered Safeguards AC (Train B),” to add procedural steps to allow restoration of the EDG not being tested in the event the diesel was needed to support Unit 1 operations.

On April 15, 2002, the inspectors were in the control room observing final preparations for ORT 3B, Step 5.4, “Loss of AC Followed by Automatic Safety Injection With G-04.” The inspectors noted that Step 5.3.19.c specified that a dedicated Level 4 operator be stationed at 125-volts direct current breaker D72-28-01 in the G-03/G-04 EDG building to perform Attachment K when directed by shift management. The intent of Step 5.3.19.c was to have the dedicated operator restore 125-volts direct current control power to the G-03 EDG so that the diesel could be aligned to support automatic operation to Unit 1. The inspectors also noted that Step 5.5.1.b directed the same operator to restart the K-3B station air compressor following the previous shedding of the air compressor during step 5.4.3 of the refueling test. Using the same dedicated operator to restart the station air compressor would have necessitated the operator leaving the G-03/G-04 building on the north side of the protected area and entering the air compressor room located on the ground elevation of the turbine building between Units 1 and 2.

The inspectors expressed concern to the duty shift manager that ORT 3B was directing the G-03 dedicated operator to perform duties with the station air compressor away from the local G-03 area. Following the inspectors’ comments, the duty shift supervisor directed that a different auxiliary operator be assigned to perform the air compressor restoration activities. The refueling test proceeded and the dedicated G-03 operator remained in the G-03/G-04 building for the remainder of the test, locally available to perform the intended functions. One of the criteria for placing safety-related mitigating equipment in service includes sufficient time available to implement the intended actions. The G-03/G-04 building was located on the north end of the protected area, approximately 100 yards up a slight hill from the station air compressor room.

The inspectors reviewed FSAR Table 14.3.2-10, “Plant Operating Range Allowed By The Best Estimate Large Break Loss-of-Coolant-Accident (LBLOCA) Analysis (Point Beach Nuclear Plant), Item g,” and noted that the LBLOCA design basis assumed that the SI time delay (with loss of offsite power) to be less than or equal to 37.0 seconds for low-head SI and less than or equal to 23.0 seconds for high head SI. The inspectors compared the time frames required by the LBLOCA design basis with the time available for the dedicated operator to have restored G-03 to service, starting from the air compressor room in the turbine building. The inspectors concluded that the dedicated operator could not have reasonably completed the actions to restore G-03 to automatic operation in a time sufficient to have met the LBLOCA design basis assumptions.

The inspectors determined that the issue of providing procedural guidance to a dedicated operator to perform ancillary duties away from the designated duty station such that the intended functions could not be performed within the bounding time limits of the design basis analyses was a performance deficiency and was of more than minor significance since the issue affected the availability and capability of the G-03 EDG, a mitigating system, to respond to Unit 1 design basis events. The inspectors used Manual Chapter 0609, Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," regarding mitigating systems and determined that:

- The finding was not a design or qualification deficiency;
- The finding did not represent an actual loss of the safety function for any mitigating system and did not result in a loss of function of a single train of any mitigating systems for greater than its TS allowed outage time;
- The finding did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours;
- The finding did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event in that the finding did not involve the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding or severe weather initiating event; and
- The finding did not involve the loss of a safety function that contributed to external event initiated core damage accident sequences.

Therefore, the finding screened as Green, very low safety significance.

Enforcement

Since the inspectors intervened and the G-03 dedicated operator did not perform ancillary duties away from the assigned duty station such that the intended G-03 functions could not have been performed within the bounding time limits of the Unit 1 LBLOCA design basis, the issue did not represent a violation of NRC requirements. Because this issue was more than a minor concern but did not involve a violation of NRC requirements, the inspectors determined that this issue constituted a Finding of very low safety significance (Green) (FIN 50-266/02-06-02).

.2 RHR Valve Exercise Prior to Placing RHR In Service During Unit 2 Shutdown

a. Inspection Scope

The inspectors reviewed design basis requirements and observed performance of inservice surveillance test IT 04D, "RHR Valve Exercise Test for Operation or Shutdown Unit 2," Revision 4, to verify operability of the RHR suction and return valves prior to placing the system in service and to verify compliance with American Society of Mechanical Engineers Section XI testing requirements. Completed surveillance test documentation was reviewed to verify that the RHR system isolation valves satisfied all required acceptance criteria and remained capable of performing the intended safety functions. The inspectors observed RHR system operating parameters during valve stroking to verify that letdown system and RHR pump system flow parameters stayed within acceptable ranges during changing system configurations. Finally, the inspectors reviewed Safety Temporary Procedure Change Number 2002-0237, "Revise Initial Condition 4.5 To Allow Performance of OP-7A/IT 04D With (1) One RCP Danger Tagged OOS," and Safety Evaluation Screening 2002-0151, "Revise IT-04D Initial

Conditions to Permit Performance with a Single RCS Loop Operable," to verify compliance with TS 3.4.6 requirements.

b. Findings

No findings of significance were identified.

.3 Unit 2 'A' Train ECCS Integrated SI Test Without G-02 (Unit 2, 'A' Train EDG) Available

a. Inspection Scope

The inspectors observed integrated SI system testing in accordance with ORT 3A, "Safety Injection Actuation With Loss of Engineered Safeguards AC Power (Train A) Unit 2," Revision 34, on April 15, 2002, to determine the ability of Unit 2 safety-related equipment to respond to a design basis accident. The inspectors reviewed Safety Evaluation 2002-0150, "ORT-3A (Revision 34), Safety Injection Actuation With Loss of Engineered Safeguards AC Power Without G-02)," to verify the adequacy of the test while the normal 2A05 safeguards bus power supply, EDG G-02, was out-of-service. Observations were performed from the control room to observe and verify the correct timing and sequence between interrelated engineering safeguards systems.

The inspectors reviewed pre-test equipment alignments and plant conditions to ensure proper system configurations. Communication practices, control room decorum, receipt of expected alarms and warning lights, supervisory overview, procedure adherence, and the interface between test and on-shift licensed personnel were observed. The inspectors also observed G-01 loading, frequency, voltage, and start times to verify that all design basis requirements were met. The inspectors observed the crew response to degraded grid conditions during the surveillance test to verify that conservative decisions were made relative to maintaining both Units 1 and 2 in stable configurations. The inspectors reviewed the completed test documentation to verify that all equipment acceptance criteria had been met and the equipment remained capable of performing the intended safety function.

b. Findings

No findings of significance were identified.

.4 Refueling Interval Overspeed Trip Test of Unit 2 Turbine-Driven AFW Pump

a. Inspection Scope

The inspectors reviewed design basis requirements and observed performance of inservice surveillance test IT 295B, “Overspeed Test Turbine-Driven Auxiliary Feedwater Pump, Refueling Interval Unit 2,” Revision 11, to verify operability of the Unit 2 turbine-driven AFW pump prior to exceeding 350°F following U2R25. The inspectors observed adjustment of the overspeed trip setpoint and witnessed three consecutive tests to verify that the turbine-driven AFW pump was returned to service with the overspeed trip setpoint within the acceptance criteria of 4410 - 4590 revolutions per minute.

b. Findings

No findings of significance were identified.

.5 Local Leak Rate Test of Unit 2 Containment Purge Valves

a. Inspection Scope

The inspectors observed performance of test TS 36, “Local Leak Test of Containment Purge Valves Unit 2,” Revision 15, to verify containment integrity of the purge system supply and exhaust valves prior to Unit 2 exceeding 200°F following U2R25. The inspectors walked down the test configuration and observed data collection to verify that the test methodology accurately characterized leakage from the V-1 and V-2 containment penetrations. The inspectors also walked down equipment to verify that the test equipment was within calibration, the boundaries of the leak rate test were properly tagged and controlled in accordance with the test procedure, and the leak rate test was conducted within the test parameters of 61 to 65 pounds per square inch gauge. The inspectors also reviewed test data to verify that the purge system supply and exhaust valve leakage rates met acceptance criteria and added the measured leakage to the remaining containment leakage values to verify that design basis integrated containment leakage rates were not exceeded. The inspectors reviewed completed test documentation and checked control room Binder TS-10A to verify that local leak rate test results from the containment purge system supply and exhaust valves had been properly transcribed into the record used by licensed operators. Finally, the inspectors highlighted procedural errors in test TS 36, Step 5.5, to the test performers to ensure that purge system supply and exhaust valve leak rates were assigned to the proper Unit. The inspectors selected the containment purge supply and exhaust valves for observation due to the large impact of these valves on the Unit 2 Large Early Release Frequency.

b. Findings

No findings of significance were identified.

.6 Station Battery D-05 Discharge Test

a. Inspection Scope

On March 26, 2002, the inspectors observed a safety-related, 'red' instrument bus, 125-volts direct current battery discharge test in accordance with Routine Maintenance Procedure (RMP) 9200-1, "Station Battery D-05 Discharge Tests and Equalizing Charge," Revision 8, to verify that the battery capacity was adequate to supply and maintain operable status of all emergency loads for the design duty cycle. The inspectors compared the battery performance test duty cycle of RMP 9200-1, Attachment B, to the design basis duty cycle defined in FSAR Figure 8.7.2, "Batteries D05, D06, D305 Duty Cycle," to verify that the RMP adequately tested design basis requirements. The inspectors also reviewed test data to verify that the battery capacity was in excess of the manufacturers rating, to verify the current surveillance interval, and to ensure that no battery capacity degradation was occurring. The inspectors monitored the licensee response to low individual cell voltages following an equalizing charge to verify that the affected cells were replaced prior to the D05 battery being returned to service. Finally, the inspectors reviewed the completed test documentation to verify that all equipment acceptance criteria had been met and the equipment remained capable of performing the intended safety function.

b. Findings

No findings of significance were identified.

.7 Unit 1 Safeguards Bus Undervoltage Relay Testing

a. Inspection Scope

During the week of June 24, 2002, the inspectors reviewed 4.16-kV undervoltage design basis requirements and observed performance of instrumentation and control surveillance test 1ICP 02.013, "4.16KV Undervoltage Matrix Relays 31 Day Surveillance Test," Revision 5, to verify operability of the 4.16-kV undervoltage relays. The inspectors observed instrumentation and control technician communications with the duty control room crew, and concurrent and independent verification practices when placing the 4.16-kV relays in test and restoring from test into service. The inspectors also reviewed the completed surveillance test procedure to verify that supervisory reviews had been properly completed.

b. Findings

No findings of significance were identified.

.8 Unit 2 Safeguards Bus Undervoltage Relay Testing

a. Inspection Scope

During the week of June 24, 2002, the inspectors reviewed 4.16-kV Undervoltage design basis requirements and observed performance of instrumentation and control surveillance test 2ICP 02.013, "4.16-kV Undervoltage Matrix Relays 31 Day Surveillance Test," Revision 6, to verify operability of the 4.16KV undervoltage relays. The inspectors observed instrumentation and control technician communication interfaces with the duty control room crew, and concurrent and independent verification practices when placing the 4.16-kV relays in test and restoring from test into service. The inspectors also reviewed the completed surveillance test procedure to verify that supervisory reviews had been properly completed.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

.1 Temporary Replacement of SW Pump Column for P-032D

a. Inspection Scope

The inspectors reviewed Temporary Modification TM 02-002, "Temporary Replacement of Service Water Pump Column for P-032D," to verify that the modification was properly installed and had no effect on the operability of the safety-related equipment. The inspectors also reviewed licensee plans to change the P-032D SW pump column to a newer style column to ensure improved seismic performance.

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 and Radiation Work Permit (RWP) Reviews

a. Inspection Scope

The inspector conducted walkdowns of the radiologically controlled area to verify the adequacy of radiological boundaries and postings. Specifically, the inspector walked down several radiologically significant work area boundaries (radiation, high radiation, locked high radiation, and very high radiation areas) in the Unit 2 containment, auxiliary building, radwaste, and SFP areas. Confirmatory radiation measurements were taken in these areas to verify that these areas were properly posted and controlled in accordance with 10 CFR Part 20, licensee procedures, and TSs. The inspector reviewed RWPs for various engineering, operations, radiation protection (RP) and maintenance activities, which were prepared to support U2R25. The RWPs were evaluated for protective clothing requirements, respiratory protection concerns, electronic dosimetry alarm setpoints, radiation protection hold points, and As-Low-As-Is-Reasonably-Achievable (ALARA) considerations to verify that work instructions and controls had been adequately specified and that electronic dosimeter setpoints were in conformity with survey indications.

b. Findings

No findings of significance were identified.

.2 Identification and Resolution of Problems

a. Inspection Scope

The inspector 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 inspector specifically reviewed ARs completed in conjunction with U2R25 and which focused on access control to radiologically significant areas, radiation worker practices, and radiation protection technician practices. The inspector reviewed these documents to assess the licensee's ability to identify repetitive problems, contributing causes, the extent of conditions, and to implement corrective actions to achieve lasting results.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

.1 Radiological Work/ALARA Planning

a. Inspection Scope

The inspector examined the station's procedures for radiological work/ALARA planning and scheduling, and evaluated the dose projection methodologies and practices implemented for U2R25, to verify that sound technical bases for outage dose estimates existed. The inspector 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 U2R25 to assess current performance and outage exposure challenges.

The inspector 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 inspector 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 inspector reviewed Total Effective Dose Equivalent ALARA evaluations developed for upper/lower reactor cavity decontamination, reactor head underneath work, upper reactor internals lift rig inspection, and cavity seal ring demolition to assess the licensee's analysis for the potential use of respiratory protection equipment during those evolutions.

b. Findings

No findings of significance were identified.

.2 Verification of Exposure Goals and Exposure Tracking System

a. Inspection Scope

The inspector reviewed the licensee's methodology and assumptions used to develop outage exposure estimates and exposure goals for U2R25. Pre-job ALARA reviews were examined to evaluate the licensee's ability to assess actual outage doses, as wellas the overall effectiveness of the work planning. The inspector 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 radiological exposure. The inspector examined job dose history files and dose reductions anticipated through lessons learned to verify that the licensee appropriately forecasted outage doses. The inspector examined the actual U2R25 radiation dose exposure data to date (i.e., ≈41 roentgen equivalent man (Person-rem), versus the projected dose ≈70 person-rem) and the outage dose goal of 130 person-rem. The inspector also reviewed the licensee's exposure tracking system to verify that the level of exposure tracking detail, exposure report timeliness, and exposure report distribution were sufficient to support control of collective exposures. Additionally, the inspector reviewed dose tracking records for all workers on selected projects to assess the 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 inspector observed work activities in the radiological controlled area that were performed in radiation areas, high radiation areas, and locked high radiation areas to evaluate the use of ALARA controls. Specifically, the inspector reviewed the adequacy of RWPs and radiological surveys, attended pre-job radiological briefings, and assessed job site ALARA controls, in part, for the following work activities:

- Removal/Replacement of Valve CV-296;
- Reactor Head measurements;
- Disassembly, operational check, and reassembly of valve SI-867B; and
- Removal of reactor head "O"-ring, "O"-ring groove decontamination and inspection.

The inspector 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 inspector 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 if 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 inspector evaluated the RP personnel, considering the possible implementation of dosimetry placement changes necessitated by significant dose rate gradients during both the CV-296 and SI-867B jobs (i.e., per the requirements of RWPs).

b. Findings

No findings of significance were identified.

.4 Source Term Reduction and Control

a. Inspection Scope

The inspector reviewed and discussed 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 U2R25 were evaluated to ensure that source term reduction plans had been appropriately implemented. The inspector reviewed selected aspects of the licensee's source term reduction program, focusing on those initiatives completed for the outage, such as flushing, lancing/desludging, and prioritizing/sequencing of installation of permanent/final temporary shielding packages and complex scaffolding arrangements, to minimize exposure. The inspector also reviewed the station's overall source term reduction plan, which included improved tracking/mitigation of hot spots, use of submicron filtration, online/shutdown chemistry initiatives, and cobalt reduction initiatives through stellite control. The inspector 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 Declared Pregnant Workers

a. Inspection Scope

The inspector reviewed the station's procedure for controlling exposures to embryos/fetuses via the controls implemented for workers who voluntarily declare their pregnancy to the licensee. Additionally, the inspector reviewed the records and controls implemented for one worker who declared her pregnancy to the station, since the last assessment period, to verify that controls were implemented in accordance with the station procedure and 10 CFR 20.1208.

.6 Identification and Resolution of Problems

a. Inspection Scope

The inspector examined the licensee's lessons learned from the Unit 1 refueling outage 26 (U1R26) dose goal estimation process and its subsequent effect on the establishment of the U2R25 dose goal. The inspector reviewed a licensee self-assessment of the ALARA program and a pre-U2R25 readiness assessment conducted by the RP department. The inspector evaluated selected outage generated CRs, which focused on ALARA planning and controls. Additionally, the inspector reviewed a post-job ALARA review for fuel transfer cart maintenance. The inspector evaluated the effectiveness of the licensee's self-assessment process to identify, characterize, and prioritize problems. Additionally, the inspector reviewed the licensee's ability to identify repetitive problems, determine contributing causes, extent of conditions, and corrective actions which would achieve lasting results.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems (71122.01)

.1 Offsite Dose Calculation Manual (ODCM), Dose Calculations, and Changes to the ODCM

a. Inspection Scope

The inspector reviewed a selection of monthly, quarterly, and annual dose calculations from the 2001 ODCM (Revision 14) to ensure that the licensee had properly calculated the offsite dose from radiological effluent releases and to determine if any annual TSs or ODCM limits (i.e., Appendix I to 10 CFR Part 50 values) were exceeded. Additionally, the inspector reviewed the ODCM for changes made by the licensee to the liquid or gaseous radioactive waste system design, procedures, or operation since the last inspection (January 2001). For each ODCM revision that impacted effluent monitoring or release controls, the inspector reviewed the licensee's technical justifications for the changes and determined if the changes were made in accordance with the TSs.

b. Findings

No findings of significance were identified.

.2 Radioactive Effluent Program Implementation Review

a. Inspection Scope

The inspector reviewed the calendar year (CY) 2001 Annual Monitoring Report to verify that the radioactive effluent program was implemented as described in the FSAR and

ODCM and to ensure that any anomalies in the release data were adequately understood by the licensee.

b. Findings

No findings of significance were identified.

.3 Gaseous and Liquid Release Data

a. Inspection Scope

The inspector reviewed the release packages for liquid effluent batch releases completed from January 2001 through May 2002, to verify that the licensee's processing and release procedures, including dose projections to members of the public, were conducted in accordance with requirements of the ODCM in TS 5.5.1 and the radioactive effluent controls program in TS 5.5.4. Additionally, the inspector selectively reviewed grab sample results and licensee calculations for containment purge radioactive gaseous releases and waste gas decay tank releases completed from January 2001 through May 2002, including the projected doses to members of the public, to verify that appropriate treatment equipment was used and that the radioactive gaseous effluents were processed and released in accordance with TS requirements. For all of the release packages reviewed, the inspector also examined the monitor alarm setpoints used and methodology employed, to verify that changes to the setpoints were made in accordance with the ODCM.

b. Findings

No findings of significance were identified.

.4 Liquid and Gaseous Release Systems Walkdowns

a. Inspection Scope

Prior to commencing walkdowns, the inspector interviewed staff members of the licensee's radiation protection, chemistry, and engineering departments responsible for implementing the liquid and gaseous radioactive waste effluent treatment and monitoring program and the system engineers responsible for maintaining the safety-related (and non-safety related) systems. The interviews were conducted to assess staff knowledge in their areas of responsibility and to obtain system performance information. The inspector performed walkdowns of the major components of the liquid effluent treatment and monitoring system (e.g., radiation and flow monitors, tanks, and pumps) to verify that the current system configuration was as described in the FSAR and the ODCM. Specifically, the inspector reviewed the material condition of the point of discharge radiation monitors and the condition of equipment in the following areas:

- vent throttle valve (WG-14A);
- waste condensate overboard discharge valve (WL-1785);
- blowdown evaporator, waste distillate overboard valve (BE-92);
- Units 1 and 2 and SFP demineralizer cubicles;

- laundry and hot shower tanks;
- chemical drain tank;
- reactor coolant drain tanks;
- waste holdup tank;
- sump tank and pumps;
- waste evaporator;
- waste condensate tanks; and
- blowdown evaporator.

Additionally, the configuration of the gaseous radioactive waste collection and processing equipment, as well as the control room emergency filtration/pressurization system, were reviewed to verify conformance with the licensee's FSAR. The inspector also evaluated the material condition of the gaseous treatment and monitoring systems to ensure that the equipment was as described in the FSAR and ODCM. In particular, the following filtration and monitoring system components were inspected:

- gas decay tanks;
- letdown gas stripper;
- condenser air ejector filtration;
- Units 1and 2 containment purge exhaust monitors (SPINGs #21 and #22);
- auxiliary building exhaust monitor (SPING #23);
- radwaste packaging (drumming) area exhaust monitor (SPING #24);
- control room (VNCR) system ventilation monitor, Data Acquisition Module (DAM) channel # 06-07,09; and
- technical support center (TSC) system ventilation;

The inspector also noted the sampling of liquid and gaseous effluents by the chemistry department staff. These activities included observing a weekly change-out of the silver zeolite (i.e. iodine) cartridge for the Control Room Iodine/Noble Gas monitoring system, as well as the taking of a liquid service water overboard sample (2RE-229). These activities were viewed, by the inspector, to verify that plant personnel could properly collect samples and demonstrate adequate analytical practices to ensure that effluents were properly quantified. Additionally, the inspector examined liquid effluent sampling procedures and selective analysis results from recent liquid effluent samples taken (e.g., "grab" and composite samples), and conducted a tour of the plant process monitors/areas where chemistry technicians would take liquid and gaseous effluent samples.

b. Findings

No findings of significance were identified.

.5 Air Cleaning Systems

a. Inspection Scope

The inspector reviewed the most recent results of the in-place filter testing of high efficiency particulate air (HEPA) filters for the health physics and drumming station ventilation systems. The inspector examined the most recent results of the in-place filter testing of HEPA filters and charcoal adsorbers for the Units 1 and 2 containment cleanup, Units 1 and 2 containment purge, chemistry lab, combined air ejector, and auxiliary building exhausts, as well as the VNCR and the TSC emergency ventilation systems. The inspector also reviewed the results of the laboratory tests performed on charcoal adsorbers sampled from the aforementioned air cleaning systems to verify that the air cleaning systems were tested in compliance with TSs and that test results met acceptance criteria. The inspector also reviewed surveillance test results for the stack and vent flow rates to verify that the flow rates and periodicity of testing were consistent with the FSAR.

b. Findings

No findings of significance were identified.

.6 Liquid and Gaseous Effluent Monitor Calibrations

a. Inspection Scope

The inspector reviewed records of instrument calibrations or maintenance performed since the last inspection for selected point of discharge effluent radiation monitors (including the associated flow rate instrumentation) to verify that these instruments had been calibrated consistent with industry standards and in accordance with station procedures. Specifically, the inspector reviewed the calibration records for:

- Waste disposal system liquid monitor (RE-218);
- Steam generator blowdown liquid monitor (Units 1&2 RE-219);
- Waste distillate overboard liquid monitor (RE-223);
- Steam generator blowdown tank outlet monitor (Units 1&2 RE-222);
- Containment noble gas monitor (Units 1&2 RE-212);
- Auxiliary building exhaust ventilation noble gas monitor (RE-214); and
- Purge exhaust noble gas monitor (Units 1&2 RE-305).

Additionally, the inspector reviewed recent modifications to effluent monitoring systems and the current effluent radiation monitor alarm setpoint values for these monitors to assess compliance with ODCM requirements. The inspector also examined the licensee's data for CY 2001 - 2002 for trending and tracking the reliability and maintenance of selected point of discharge effluent radiation monitors. The inspector performed this review to assess the adequacy of the licensee's efforts to improve the overall effectiveness of the effluent and process radiation monitoring system.

b. Findings

No findings of significance were identified.

.7 Analytical Instrumentation Quality Control (QC)

a. Inspection Scope

The inspector reviewed the quality control data and charts for the radio-chemistry instrumentation systems used to identify and quantify effluent release and environmental samples, to verify the equipment was properly maintained consistent with station procedures, and to ensure that effluent concentrations were accurately calculated. This included a review of the licensee's gamma spectroscopy/spectrometry systems, liquid scintillation instruments, and associated instrument control charts.

b. Findings

No findings of significance were identified.

.8 Interlaboratory Comparison Program

a. Inspection Scope

The inspector reviewed the results of the CY 2001 and First Quarter 2002 Inter-Laboratory Comparison Program in order to assess the quality of radioactive effluent sample analyses performed by the licensee. The inspector reviewed the licensee's quality control evaluation of the inter-laboratory comparison program and associated corrective actions for any deficiencies identified.

b. Findings

No findings of significance were identified.

.9 Identification and Resolution of Problems

a. Inspection Scope

The inspector reviewed CY 2001 to First Quarter 2002 licensee quality assurance audits and chemistry/radiation protection departments self-assessments which were used to evaluate, identify, characterize, and prioritize problems with the radioactive waste effluent treatment and monitoring program. The reviews were conducted to verify that radiological effluent issues were adequately addressed.

The inspector also reviewed selected ARs that related to the liquid and gaseous radioactive waste effluent program, which were written during the last assessment period. The inspector reviewed these documents to assess the licensee's ability to enter identified problems into their corrective action program, note repetitive problems, identify contributing causes, and assess the extent of conditions. The inspector also reviewed these documents to verify that deficiencies were appropriately resolved in a timely manner and that the licensee's corrective action program would achieve long-lasting results.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP1 Access Authorization Program (Behavior Observation Only) (71130.01)

a. Inspection Scope

The regional security inspector interviewed five supervisors and five non-supervisors (both licensee and contractor employees) to determine their knowledge level and practice of implementing the licensee's behavior observation program responsibilities. Selected procedures pertaining to the Behavior Observation Program and associated training activities were also reviewed. Also, licensee fitness-for-duty semi-annual test results were reviewed. In addition, the inspector reviewed a sample of licensee self-assessments, audits, and security logged events. The inspector also interviewed selective licensee and contractor security managers to evaluate their knowledge and use of the licensee's corrective action system.

b. Findings

No findings of significance were identified.

3PP2 Access Control (Identification, Authorization and Search of Personnel, Packages, and Vehicles) (71130.02)

a. Inspection Scope

The regional security inspector reviewed the licensee's protected area access control testing and maintenance programs and selective procedures. The inspector observed licensee testing of all access control equipment located at the protected area portal to determine if testing and maintenance practices were effective and performance based. On at least two occasions, during peak ingress periods, the inspector observed in-processing search of personnel, packages, and vehicles at the licensee's protected area portal to determine if those practices were conducted in an effective manner and were in accordance with regulatory requirements. Interviews with randomly selected security personnel were conducted and records were reviewed to verify that security staffing levels were consistently and appropriately implemented. Also the inspector reviewed the licensee's process for limiting access to only authorized personnel to the protected area and vital equipment by a selected sample review of access authorization lists and actual vital area entries. The inspector reviewed the licensee's program to control hard-keys and computer input of security-related personnel data.

The regional security inspector reviewed a random sample of licensee self-assessments, audits, maintenance request records, and security logged events for identification and resolution of problems. In addition, the inspector interviewed security licensee and contract managers to evaluate their knowledge and use of the licensee's corrective action system.

b. Findings

No findings of significance were identified.

3PP4 Security Plan Changes (71130.04)

a. Inspection Scope

The inspector reviewed revisions to the Point Beach Independent Spent Fuel Storage Installation Security Plan and Point Beach Security Training and Qualification Plan to verify that changes did not decrease the effectiveness of the submitted documents. The referenced revisions were submitted in accordance with 10 CFR 50.54(p) by a licensee letter dated July 25, 2001. (Note: In addition to the revisions noted above, the July 25, 2001, transmittal also included changes to Appendix B of the Security and Safeguards Contingency Plan dated March 30, 2001. These revisions are being reviewed separately.)

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems

4OA1 Performance Indicator (PI) Verification (71151)

.1 High Pressure Safety Injection (HPSI) System Unavailability

a. Inspection Scope

During the week of May 20, 2002, the inspectors reviewed portions of the Units 1 and 2, 2000 and 2001 data for the HPSI System Unavailability PIs using the definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Indicator Guideline," Revision 2.

The inspectors reviewed station log entries, selected procedures, and system engineer data sheets 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.

b. Findings

No findings of significance were identified.

.2 Unplanned Scrams per 7,000 Critical Hours

a. Inspection Scope

During the week of June 17, 2002, the inspectors reviewed licensee records to verify the Unplanned Scrams per 7,000 Critical Hours PIs for Units 1 and 2 for the last three quarters of 2001 and the first two quarters of 2002. The inspectors used the definitions and guidance contained in NEI 99-02, Revision 2, for this review.

b. Findings

No findings of significance were identified.

.3 Scrams With Loss of Normal Heat Removal

a. Inspection Scope

During the week of June 24, 2002, the inspectors reviewed portions of the Units 1 and 2, 1999, 2000, and 2001 data for the Scrams With Loss of Normal Heat Removal PIs using the definitions and guidance contained in NEI 99-02, Revision 2.

The inspectors reviewed station log entries, Licensee Event Reports (LERs), and PI coordinator data sheets to verify that all scrams with loss of normal heat removal had been characterized correctly in determining PI results.

b. Findings

No findings of significance were identified.

.4 Radiological Effluent TS (RETS) OCDM Radiological Effluent Occurrence

b. Inspection Scope

During the week of June 7, 2002, the inspector reviewed selected ARs for CYs 2001-2002 and offsite dose calculations (January 2001 through first quarter 2002) to identify any occurrences that were not identified by the licensee and to verify that the licensee had accurately reported the PI for the public radiation safety cornerstone. The inspector discussed the RETS/ODCM PI data collection and analysis process with the data steward for this indicator, to verify that the program was implemented consistent with industry guidelines provided in NEI 99-02, Revision 2, and licensee procedures.

b. Findings

No findings of significace were identified.

.5 Security

a. Inspection Scope

During the week of June 7, 2002, the regional security inspector reviewed the data for the Physical Protection PIs: Fitness-For-Duty/Personnel Reliability, Personnel Screening Program, and Protected Area Security Equipment. Specifically, a sample of plant reports related to security events, security shift activity logs, fitness-for-duty reports, and other applicable security records were reviewed for the period between April 2001 and May 2002. In addition, licensee security management personnel were interviewed regarding their interpretation and application regarding the adjustment of data they submitted for the protected area security equipment PI. The threshold level was not affected.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Initial Licensee Response to Density Compensation Errors Associated With The Use of Steam Generator Narrow Range Level Detector During Cold Shutdown Plant Conditions

a. Inspection Scope

During the week of June 3, 2002, the inspectors reviewed the licensee response to the inspector's discovery of previously unnoticed density compensation errors associated with the steam generator narrow range level indication during cold plant conditions. The inspectors reviewed the licensee's response to assess internal communication capabilities, the ability of the licensee to perform adequate extent-of-condition reviews, and the ability of the licensee to understand the full impact of the issue on plant operations.

a. Findings

As discussed in Section 1R20.4 of this report, on April 26, 2002, during U2R25 the inspectors identified that the steam generator narrow range level detectors, calibrated for normal, hot steam generator operating conditions of 521°F and 821 pounds per square inch absolute, were being used during cold plant conditions to satisfy TS surveillance requirements 3.4.5.2, 3.4.6.2, and 3.4.7.2. As a result of this error, as steam generator water temperatures decreased (and level detector variable leg water densities increased) during a plant shutdown and cooldown, the difference between the steam generator narrow range indicated and actual steam generator water level increased in the non-conservative direction. At 200 °F, this unaccounted density error resulted in a condition where the actual water level was 4 percent lower (closer to the top of the U-tube bundle) than indicated.

As a result of the inspectors' observation, a licensee instrumentation and control engineer initiated AR 3112, "Steam Generator Narrow Range Level Uncertainty at Lower Temperature," on April 30, 2002. In the AR, the engineer acknowledged the inspectors' observation and recommended that the parametric value for the steam generator narrow range level indication in Engineering Evaluation 2001-0032, "Parametric Values," Revision 2, be changed from 33 percent to 38 percent in Modes 3, 4, and 5. The licensed senior reactor operator who screened the AR on April 30 recommended that calculations be verified to ensure that logs, mode change CLs, and TSs were changed as required. The senior reactor operator determined that Unit 2 steam generators were operable on April 30 since the Unit was in Mode 6 (refueling shutdown) and the steam generators were not required as a method of decay heat removal for the associated plant conditions. The senior reactor operator also noted that steam generator level indication might be required when Unit 2 subsequently returned to Mode 5 (cold shutdown) following refueling activities. The inspectors reviewed licensee procedure changes following initiation of AR 3112 and noted that on May 1, 2002, procedure feedback Form 2002-00746 revised the control room daily log sheet, Stations 148 through 153, to change the minimum required steam generator narrow range level indication to greater than or equal to 38 percent narrow range in Modes 3, 4, and 5.

Action request 3112 was screened by the management review committee on May 2, 2002, and a Level B Apparent Cause Investigation was assigned in accordance with procedure NP 5.3.1, “Action Request Process,” Revision 19. The licensee completed the apparent cause evaluation on May 16 and concluded that a contributing cause of the density error was a failure in the communication process between Improved TS implementation and engineering personnel to precisely define the conditions of use and the limitations associated with the steam generator narrow range level indication instrument. The extent-of-condition review associated with the apparent cause evaluation for AR 3112 did not identify any other plant procedures needing revision as a result of the steam generator narrow range level detector density compensation issue.

On May 22, 2002, the inspectors reviewed selected plant procedures to check the rigor of the previous extent-of-condition reviews concerning the steam generator narrow range level instrument density compensation issue. The inspectors identified that safety-related shutdown procedure SEP [Shutdown Emergency Procedure] 3.0 “Loss of All AC [Alternating Current] Power to a Shutdown Unit - Unit 1,” Revision 12, and SEP 3.0, “Loss of All AC Power to a Shutdown Unit - Unit 2,” Revision 13, Steps 5.b and 8.b, utilized steam generator narrow range level indication values of 29 percent to ensure that the secondary side of the top of the U-tubes remained covered with water to support use of the steam generator as a secondary heat sink and for reactor decay heat removal via natural circulation. As discussed in Section 1R20.4 of this report, SEP 3.0 created the possibility of uncovering the secondary side of the top of the steam generator U-tubes thereby impacting the ability to remove reactor decay heat. The inspectors provided the SEP 3.0 observations to licensee instrumentation and control engineering and operations personnel on May 23.

Following the inspectors’ observations of May 22, the licensee re-performed extent-of-condition reviews and wrote 12 other procedure feedback forms for the following safety-related procedures;

- Inservice Test (IT) 03D, “RHR Valve Exercise Test for Operation or Shutdown Unit 1,” Revision 4
- IT 04D, “RHR Valve Exercise Test for Operation or Shutdown Unit 2,” Revision 4
- IT 03C, “HHSI [High Head Safety Injection] Check Valve Exercise Test in Cold Shutdown - Unit 1,” Revision 4
- IT 04C, “HHSI Check Valve Exercise Test in Cold Shutdown - Unit 2,” Revision 5
- IT 03B, “LHSI [Low Head Safety Injection] Valve Exercise Test in Cold Shutdown Unit 1,” Revision 7
- IT 04B, “LHSI Valve Exercise Test in Cold Shutdown Unit 1,” Revision 6

- TS Test TS 30, “High and Low head Safety Injection Check Valve Leakage Test Unit 1,” Revision 23
- TS 31, “High and Low Head Safety Injection Check Valve Leakage Test Unit 2,” Revision 23
- Operations Refueling Test (ORT) 3B, “Safety Injection Actuation With Loss of Engineering Safeguards AC (Train B) Unit 2,” Revision 33
- ORT 3B, “Safety Injection Actuation With Loss of Engineering Safeguards AC (Train B) Unit 1,” Revision 32
- ORT 3A, “Safety Injection Actuation With Loss of Engineering Safeguards AC (Train A) Unit 1,” Revision 35
- ORT 3A, “Safety Injection Actuation With Loss of Engineering Safeguards AC (Train A) Unit 2,” Revision 34

The inspectors concluded, based on the May 22 observation concerning SEP 3.0 and the number of procedures requiring revision once the extent of condition reviews had been re-performed, that the licensee's initial extent of condition review concerning the density compensation issue had not been sufficiently rigorous to identify the full impact of the issue on plant operations. The inspectors noted that failure in the internal communication process that contributed to procedure revisions delays was also the same apparent cause identified in AR 3112, making the rigor of internal communication processes a repeat issue.

4OA3 Event Follow-up (71153)

.1 (Closed) LER 301/2002-001-00: Completion of Nuclear Plant Shutdown Required By Limiting Condition for Operation 3.5.2 Required Action B.1. On February 20, 2002 at approximately 1:00 a.m., the Unit 2 'B' train safety injection pump, 2P-15B, was damaged during licensee performance of a monthly preventative maintenance procedure to ensure bearing lubrication. Technical Specification Action Condition 3.5.2.A.1 was entered which required an inoperable emergency core cooling train be restored to an operable status within 72 hours. Subsequent inspection of the pump revealed damage to the rotating element, the coupling and shaft keys between the pump and the motor, the pump internal wearing rings, and other components. The licensee concluded that the cause of the pump damage was gas binding as a result of back-leakage of nitrogen-saturated fluid from the 'A' SI accumulator, 2T-34A, through two or more check or closed valves to the discharge of the SI pump. When it became apparent that pump repairs and testing would exceed the TS Action Condition completion time, the licensee shutdown Unit 2. Unit 2 reached Mode 3, hot standby, at 7:26 p.m. on February 22, 2002, approximately 66 hours after the 2P-15B SI pump failed on February 20. The shutdown occurred without complications and all equipment required for the shutdown performed as expected.

Inspector reviews of the SI pump failure, corrective action program deficiencies, and the associated operability evaluation were documented in NRC Inspection Report 50-266/02-03(DRP), 50-301/02-03(DRP); Section 4OA2.c.(2); Inspection Report 50-266/02-05(DRP), 50-301/02-05(DRP); Sections 1R14.1, 1R15.1, 1R15.2, and 4OA2.1; Inspection Report 50-266/02-05(DRP), 50-301/02-05(DRP); and letters dated May 14 and June 13, 2002. The inspector review of this LER did not identify any new issues. The 2P-15B SI pump failure and the forced Unit 2 shutdown were entered into the licensee's corrective action program (CAP) as CAP 002245.

4OA5 Other

.1 Circumferential Cracking of Reactor Pressure Vessel 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 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," to verify compliance with applicable regulatory requirements. In accordance with the Bulletin, Point Beach Nuclear Plant Unit 2 was characterized as belonging to the sub-population of plants (Bin 3) that were considered to have a moderate susceptibility to primary stress corrosion cracking based upon a susceptibility ranking of more than 5 but less than 30 effective full power years of operation from that of the Oconee Nuclear Station, Unit 3, condition. As a result, Point Beach responded to the Bulletin by performing a direct visual examination of the reactor vessel head. The inspectors interviewed inspection personnel, reviewed procedures and inspection reports, including photographic and video tape documentation, to assess the licensee's efforts in conducting an "effective" visual examination of the reactor vessel head.

Evaluation of Inspection Requirements

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

The inspectors determined that the examinations were performed by personnel certified as Level II or Level III VT-2 in accordance with the Point Beach Nuclear Plant "Nondestructive Examination Procedures Manual." In addition, the licensee provided the individuals with training specific to the guidelines described by the Electric Power Research Institute, "Visual Examination for Leakage of PWR Reactor Head Penetrations."

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

The inspectors verified that the examinations were conducted in accordance with plant approved, Nondestructive Examination Procedure, NDE-757, Revision 0, "Visual Examination for Leakage of Reactor Pressure Vessel Closure Head Penetrations." The inspectors determined that the procedure was appropriate for the examinations. In addition, the licensee constructed a full-size training mockup of the reactor head to familiarize the personnel involved with asbestos insulation removal and the subsequent visual examination.

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

The inspectors determined through a review of post-examination records in the form of video tape and pictures, discussions with the personnel that conducted the examinations, and a review of the procedure, that the examinations were sufficient to identify any deficiencies. The licensee's examinations did not identify any deficiencies, therefore, the inspectors did not assess the licensee's efforts to disposition or resolve deficiencies.

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

The inspectors determined through interviews with inspection personnel, and reviews of procedures and inspection reports, including video tape and photographic documentation of the examinations, that the licensee's efforts were capable of identifying the results of the phenomenon described in the Bulletin. 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.

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

The Point Beach Unit 2 reactor pressure vessel had 3-inch thick block contoured asbestos insulation. The 3" blocks were in direct contact with the head; however they were not bonded to the head. The blocks were coated with 1/4" Fiberfax cement which was sealed with a waterproof coating. The inspectors determined that prior to the examinations, the licensee completely removed the insulation. The inspectors also determined through discussions with the inspection personnel and viewing of the videotape that the as-found pressure vessel head condition was relatively clean (with only bits of insulation and cement present), with no viewing obstructions to the exam. The inspection personnel fully examined the 49 pressure vessel head penetrations, including the 3/4" head vent.

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

The inspectors verified, through interviews with inspection personnel and review of the video tape and photographic record of the examination, that small boron deposits, as described in the Bulletin, could be identified; given the cleanliness and accessibility of the pressure vessel head penetrations. However, no indications were found on the 49 pressure vessel head penetrations, including the 3/4" head vent.

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

Through a review of the examination records, the inspectors determined that the inspection personnel did not identify any materiel deficiencies associated with any of the 49 pressure vessel head penetrations, including the 3/4" head vent.

(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. Radiation doses received as a part of the examinations included 3.484 person-rem, associated with removal of the insulation/visual inspection, 0.634 person-rem for shroud removal, and 0.728 person-rem for installation of new insulation. The shroud and new insulation will have 6 viewing ports installed to further aid future inspections of the head and to reduce dose associated with insulation removal.

b. Findings

No findings of significance were identified.

4OA6 Meetings

Exit Meeting

The resident inspectors presented the routine inspection results to Mr. M. Warner and other members of licensee management on June 24, 2002. The licensee acknowledged the findings presented. No proprietary information was identified.

Interim Exit Meeting

Senior Official at Exit Meeting:	M. E. Warner, Kewaunee/Point Beach Site Vice-President
Date:	April 26, 2002
Proprietary:	No
Subject:	Access Control to Radiologically Significant Areas And ALARA Planning and Control
Change to Inspection Program:	No

Interim Exit Meeting

Senior Official at Exit Meeting:	M. E. Warner
Date:	April 26, 2002
Proprietary:	No
Subject:	Temporary Instruction 2515/145 and Inservice Inspection
Change to Inspection Program:	No

Interim Exit Meeting

Senior Official at Exit Meeting:	M. E. Warner
Date:	May 7, 2002
Proprietary:	No
Subject:	2P-15B Safety Injection Pump Failure Due to Gas Binding, Preliminary White Finding
Change to Inspection Program:	No

Interim Exit Meeting

Senior Official at Exit Meeting:	T. Taylor, Point Beach Plant Manager
Date:	June 7, 2002
Proprietary:	No
Subject:	Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems; and Performance Indicator Verification for RETS/ODCM Radiological Effluent Occurrence
Change to Inspection Program:	No

Interim Exit Meeting

Senior Official at Exit Meeting:	M. E. Warner
Date:	June 14, 2002
Proprietary:	No
Subject:	Security, Access Control
Change to Inspection Program:	No

Interim Exit Meeting

Senior Official at Exit Meeting:	M. E. Warner
Date:	June 14, 2002
Proprietary:	No
Subject:	Biennial Heat Sink
Change to Inspection Program:	No

Interim Exit Meeting

Senior Official at Exit:	A. J. Cayia, Kewaunee/Point Beach Site Director
Date:	June 14, 2002
Proprietary (explain "yes"):	Yes. PGT-2002-1270, Analysis of the 1HX-012A HX-012B CCW Heat Exchangers Testing performed on April 14, 2002, with procedure OR-152; PGT-2001-1180, Analysis of the 1HX-012A HX-012B CCW Heat Exchangers Testing performed on April 8, 2001, with procedure OR-152; PGT-99-1416, Analysis of Results of CCW Heat Exchangers HX-12A and HX-12B performed October 17, 1999, during U1R25; TIN 97-1177, Test Protocol CCW Heat Exchanger.

Subject: Biennial Heat Sink
Change to Inspection Findings: No

4OA7 Licensee-Identified Violations

The following finding of very low significance was identified by the licensee and was a violation of NRC requirements which met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a Non-Cited Violation.

If you deny this Non-Cited Violation, you should provide a response with the basis for denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 2055-0001; with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 2055-0001, and the NRC Resident Inspector at Point Beach.

Requirement Licensee Failed to Meet

Code of Federal Regulations 10 CFR Part 50, Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979," Section III.L.2.b, "Alternative and Dedicated Shutdown Capability," requires, in part, that the reactor coolant makeup function be capable of maintaining the reactor coolant level within the level indication in the pressurizer for PWRs [Pressurized Water Reactors]. Contrary to this requirement, failure of the licensee to have sufficient nitrogen back-up capacity available for the charging pump speed control function resulted in the inability of the licensee to maintain pressurizer level above zero percent indicated level for approximately a 2.5 hour period during an Appendix R safe shutdown scenario. This issue has been included in the licensee's corrective action program as CAP 002701.

KEY POINTS OF CONTACT

<u>Licensee</u>
J. Anderson, Production Planning Manager
L. Armstrong, Site Engineering Director (Acting)
C. Arnone, Outage Manager
A. Cayia, Site Director
R. Cleveland, Access Authorization Manager
G. Correll, Chemistry Manager
M. Fencl, Security Manager
D. Hettick, Performance Assessment Manager
N. Hoefert, Engineering Programs Manager
V. Kaminskas, Maintenance Manager
K. Peveler, Nuclear Oversight Manager
R. Pulec, Site Assessment Manager
R. Repshas, Site Services Manager
D. Schoon, Operations Manager
J. Strharsky, Assistant Operations Manager
T. Taylor, Plant Manager
S. Thomas, Radiation Protection Manager
R. Turner, Inservice Inspection Manager
P. Walker, Training Manager
M.E. Warner, Site Vice President
T. Webb, Licensing Manager

<u>NRC</u>
D. Spaulding, Point Beach Project Manager, NRR

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-301/2002-001-00	LER	Completion of nuclear plant shutdown required by limiting condition for operation (LCO) 3.5.2 required action B.1 (Section 4OA3.1)
50-301/02-06-01	URI	Use of Steam Generator Narrow Range Level Detector During Cold Shutdown Plant Conditions (Section 1R20.1)
50-266/02-06-02	FIN	Unit 2 ‘B’ Train Emergency Core Cooling System Integrated SI Test (Section 1R22.1)

Closed

50-301/2002-001-00	LER	Completion of nuclear plant shutdown required by limiting condition for operation (LCO) 3.5.2 required action B.1 (Section 4OA3.1)
50-266/02-06-02	FIN	Unit 2 'B' Train Emergency Core Cooling System Integrated SI Test (Section 1R22.1)

Discussed

None

LIST OF ACRONYMS USED

AC	Alternating Current
AFW	Auxiliary Feedwater
ALARA	As-Low-As-Is-Reasonably Achievable
AOP	Abnormal Operating Procedure
AR	Action Request
ARB	Annunciator Response Book Procedure
CAP	Corrective Action Program
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CL	Checklist
CR	Condition Report
CY	Calendar Year
DAMS	Date Acquisition Module System
DBD	Design Basis Accident
DC	Direct Current
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
FSAR	Final Safety Analysis Report
HELB	High Energy Line Break
HEPA	High Efficiency Particulate Air
HPSI	High Pressure Safety Injection
HVAC	Heating, Ventilation, and Air Conditioning
HX	Heat Exchanger
ISI	Inservice Inspection
IT	Inservice Test
KV	Kilovolt
LBLOCA	Large Break Loss-of-Coolant Accident
LER	Licensee Event Report
NEI	Nuclear Energy Institute
NMC	Nuclear Management Company, LLC
NP	Nuclear Plant Procedure
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
OI	Operating Instruction
OP	Operating Procedure
ORT	Operations Refueling Test
OWA	Operator Workaround
P&ID	Piping and Instrument Diagram
PAB	Primary Auxiliary Building
PBF	Point Beach Form
PBSAP	Point Beach Security Administrative Procedure
PBNP	Point Beach Nuclear Plant
PC	Periodic Checks

PI	Performance Indicator
PMT	Post-Maintenance Testing
PS	Public Radiation Safety
QC	Quality Control
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RETS	Radioactive Effluents Technical Specification
RHR	Residual Heat Removal
RMP	Routine Maintenance Procedure
RP	Radiation Protection
RPS	Reactor Protection System
RV	Reactor Vessel
RWP	Radiation Work Permit
RX	Reactor
SEP	Shutdown Emergency Procedure
SFP	Spent Fuel Pool
SI	Safety Injection
SOP	System Operating Procedure
SPING	Special Particulate, Iodine, and Noble Gas
SRSS	Square Root of the Sum of the Squares
SSA	Shutdown Safety Assessment
SSC	Structure, System, or Component
SW	Service Water
TCN	Temporary Change Notice
TDAFWP	Turbine Driven Auxiliary Feedwater Pump
TEDE	Total Effective Dose Equivalent
TLD	Thermoluminescent Dosimeter
TSC	Technical Support Center
TS	Technical Specification
U1R26	Unit 1, Refueling Outage 26
U2R25	Unit 2, Refueling Outage 25
URI	Unresolved Item
UT	Ultrasonic Testing
VAC	Volts-Alternating Current
VNCR	Control Room Ventilation System
WO	Work Order

LIST OF DOCUMENTS REVIEWED

1R01 Adverse Weather

Abnormal Operating Procedure (AOP) - 13C	Severe Weather Conditions	July 23, 2001
FSAR Section 2	Site and Environment	June, 2000
PC 49 Part 6	Securing From Cold Weather	Revision 11
PCR004126 (Procedure Change Request)	Revise PC 49 Part 6 to Require a Crew Briefing on Warm Weather Preparations, Prior to May 1 of Each Year	March 25, 2002
OI 35B (Operating Instruction)	Electrical Equipment General Information	Revision 5

1R04 Equipment Alignment

Piping and Instrument Diagram (P&ID) M-209, Sheet 3	Instrument Air	Revision 11
P&ID M-209, Sheet 4	Instrument Air	Revision 35
P&ID M-209, Sheet 5	Instrument Air	Revision 26
Checklist (CL) CL 9R	Instrument Air	Revision 19
System Operating Procedure (SOP) 0-SOP-IA-001	Operation of Instrument Air Compressors	Revision 4
0-SOP-IA-002	Operation of Instrument Air Dryers and Filters	Revision 2
DBD-33	Containment Structures and Penetrations	December 22, 1994
110E035 Sheet 3	Safety Injection System	Revision 43
FSAR Section 6.4	Containment Spray	June, 2001
CL 7A	Safety Injection System Checklist Unit 2	Revision 20
2-TS-ECCS-001	Safeguard Systems Valve and Lock Checklist (Monthly) Unit 2	Revision 1
CL 10B	Service Water Safeguards Lineup	Revision 52

1R05 Fire Protection

Fire Hazards Analysis Report	Fire Zone 151, Safety Injection Pump Room	August 17, 2001
Fire Hazards Analysis Report	Fire Zone 142, Component Cooling Water Pump Room	August 17, 2001
Fire Hazards Analysis Report	Fire Zone 552, Service Water Pump Room	August 17, 2001
Fire Hazards Analysis Report	Fire Zone 582, Oil Storage Room	August 17, 2001
Fire Hazards Analysis Report	Fire Zone 273, HVAC [Heating, Ventilation, and Air Conditioning] Fan Room - Unit 2.	August 17, 2001
Fire Hazard Analysis Report	Fire Zone 272, HVAC Fan Room - Unit 1	August 17, 2001
Fire Hazards Analysis Report	Fire Zone Fire Zone 104, RHR Pump Room - 1P10A	August 17, 2001
Fire Hazards Analysis Report	Fire Zone Fire Zone 105, RHR Pump Room - 1P10B	August 17, 2001

1R06 Flood Protection Measures

NP - 8.4.17	PBNP Flooding Barrier Control	Revision 0
PC - 21 Part 4	Miscellaneous Data [Periodic Checks]	Revision 9
PC - 80 Part 7	Lake Water Level Determination	Revision 0
AOP - 9A	Service Water System Malfunction, Steps 10 - 15, and Attachment B, Service Water Flooding	Revision 13
IT - 40	Safety Injection Valves (Quarterly) Unit 1, Section 5.4, Miscellaneous LHSI Pump Room Tests	Revision 43
DBD - T - 41	Hazards - Internal and External Flooding [Module A], PBNP Topical Design Basis Document	Revision 0
NEPB - 87- 250	Evaluation of INPO SOER 85-5 (Evaluation of Internal Flooding of Power Plant Buildings)	April 16, 1987
NEPB - 85 - 213	Response to INPO SER 50-84 and Supplement 1	August 6, 1985

NRC SER	High Energy Line Failure Outside of Containment, Sections 2.0, 7.0, and 9.0	May 7, 1976
CR 97-1497	North Circulating Water Pump House Manhole Does Not Have A Means To Be Pumped Anywhere	May 6, 1997
CR 00-0126	Heating Ventilation and Air Conditioning Room Flooding Mitigation Feature Contrary to Commitment	January 13, 2000
CR 00-1830	Door Sweep Gaps Inadequate	June 14, 2000
CR 01-0238	Improper Barrel Storage	January 22, 2001
CR 01-0722	Flood Barrier Out of Service Extended Time Door 014	March 8, 2001
CA002713	North Circulating Water Pump House Manhole Does Not Have A Means To Be Pumped Anywhere - CR 97-1497	January 3, 2002
EWR 99-043	VNCR Equipment Room Drains	April 8, 1999
(Annunciator Response Book Procedure) ARB C01 A1-11	Aux Bldg -19 ft Sump Level High	Revision 4
ARB C01 A2-11	Aux Bldg North Sump Level High	Revision 3
ARB C01 A3-11	Aux Bldg South Sump Level High	Revision 3
ARB C01 A4-11	Unit 1 or 2 RHR Pump Rooms Level High	Revision 5
ARB C01 C3-11	Fuel Oil Pump House Sump Level High	Revision 5
ARB 2C20 B3-5	Unit 2 Turbine Building Sump Level High	Revision 3
ARB 2C20 B4-5	Unit 2 Facade Sump Level High	Revision 4
ARB 1C20 B3-5	Unit 1 Turbine Building Sump Level High	Revision 1
ARB 1C20 B4-5	Unit 1 Facade Sump Level High	Revision 1
AR 3333	Various Flooding Issues	May 17, 2002

1R07 Heat Sink Performance Calculations

PGT-2002-1270	Analysis of the 1HX-012A and HX-012B CCW Heat Exchangers Testing Performed on April 14, 2002 with Procedure OI-152	Revision 0

PGT-2001-1180	Analysis of the 1HX-012A and HX-012B CCW Heat Exchangers Testing Performed on April 8, 2001 with Procedure OI-152	Revision 0
PGT-99-1416	Analysis of Results of CCW Heat Exchangers HX-12A and HX-12B Performed October 17, 1999 During U1R25	Revision 0
TIN 97-1177	Test Protocol CCW Heat Exchanger	Revision 1
PGT-400042	PGT Instrument Pretest and Post-test Calibrations for April 8, 2001 Test	Revision 0
PO 4500342994	Flowmeters Pretest and Post-test Calibrations for April 8, 2001	Revision 0
28-6670	PGT Instrument Pretest Calibrations for October 17, 1999 test	Revision 0
28-6670	PGT Instrument Post-test Calibrations for October 17, 1999	Revision 0
E28667	Flowmeters Pretest and Post-test Calibrations for October 17, 1999	Revision 0
97-0118	Capability to Achieve Cold Shutdown in Both Units with One CCW Pump and Two CCW Heat Exchangers	June 25, 1997
97-0118-00-A	Capability to Achieve Cold Shutdown in Both Units with One CCW Pump and Two CCW Heat Exchangers	September 8, 1999
Engineering Evaluation 2001-0036	CC [CCW] HX Testing and Acceptance Criteria	Revision 0
N-90-067	Containment Sump Water Cooling By RHR During Recirc Mode for Input to CS Pump NPSH Available Calc N-90-45	Revision 0
N-94-059	CCW, HX-012A-D, Service Water Flow Verses Temperature Requirement	Revision 0
96-0103	Cooling of Recirculation Flow by the RHR HX Post-LOCA	Revision 0

Condition Reports Initiated as a Result of Inspection

CAP028468	NRC Identified Failure to Supercede All Appropriate Calculations upon Issue of a Revision	June 13, 2002
CAP028467	NRC Identified Inappropriate Value for CCW Flow to CCW HX Used in Calculation	June 13, 2002

Condition Reports

CAP028437	G-01 Diesel Cooler Zebra Mussel and Lake Weed Fouling	June 11, 2002
CR 01-1006	Maintenance of Heat Exchanger Program	April 2, 2001
CR 01-3514	Review of GL 89-13 Program Document and the Miscellaneous Heat Exchangers Cleaning and Inspection Program Document	November 15, 2001
CAP001352	Improved Guidance In Heat Exchanger Program Recommended	November 16, 2001
CR 00-0300	EPIP [Emergency Plan Implementing Procedure] 1.2 Does Not Classification Contain Category for Loss of Feed/Heat Sink	January 26, 2000
CAP001240	Temporary ID Tags Not Removed	November 1, 2001
CAP001270	Blowdown Valve Failed to Shut	November 6, 2001
CAP001363	DBDOI [DBD Operating Instruction] Tracking for DBD-12	November 20, 2001
CAP001369	Administrative Control of Heat Exchanger Plugs	November 20, 2001
CAP001386	PRA [Probabilistic Risk Assessment] Model Error-Waste Gas Heat Exchanger	November 20, 2001
CAP001998	NMC Eddy Current Program Gap Analysis	January 8, 2002
CAP001413	Spent Fuel HX Performance Test Concerns	November 28, 2001
CAP001831	Unit 2 HDT [Heater Drain Tank] Sample Line HX Gasket Leak	January 9, 2002
CAP002688	Indication of Service Air Compressor Aftercooler Leaks	March 27, 2002
CR 01-3109	SW Inlet Check Valve to IA [Instrument Air] Aftercooler Failed	October 10, 2001

CR 01-2931	Conflicting Procedural Guidance for Adjusting CCW Temperature Control	September 25, 2001

<u>Correspondence</u>

NPL 96-0113	Response to Westinghouse Verbal Request for Further Information to Support an Evaluation of the Containment Integrity Analysis	April 3, 1996

<u>Internal Correspondence</u>

NPM 2000-0054	Miscellaneous Heat Exchanger Inspection Summary	January 19, 2000

<u>Vendor Drawings</u>

Atlas D-9643	CCW Heat Exchanger	Revision 4
PB 01MSIG14100102	PBNP Vertical Residual Heat Exchanger Unit 1	Revision 2
Westinghouse 4837-1	Vertical Residual Heat Exchanger	August 17, 1967
Westinghouse 4836-2	Vertical Residual Heat Exchanger	September 18, 1967
Westinghouse 4808-8	Vertical Residual Heat Exchanger	May 3, 1967

<u>P&IDs</u>

PB 01 MWSK00000454	P & ID Service Water	Revision 48
PB 01 MWSK00000359	P & ID Service Water	Revision 59
PB 01 MWSK00001020	P & ID Service Water	Revision 19
PB 01 MWSK00000139	P & ID Service Water	Revision 39
PB 01 MWSK00000221	P & ID Service Water System	Revision 21
PB 02 MWSK00000254	P & ID Service Water	Revision 54

PB 02 MWSK00000254	P & ID Service Water	Revision 54
PB 02 MWSK00000509	P & ID Service Water System	Revision 9
PB01 MCCK00000137	P & ID Auxiliary Coolant System	Revision 37
PB 01 MSFK00000257	P & ID Auxiliary Coolant System	Revision 57
PB01 MCCK00000421	P & ID Auxiliary Coolant System	Revision 21
PB 02 MSFK00000149	P & ID Auxiliary Coolant System	Revision 49
PB 02 MSFK00000340	P & ID Auxiliary Coolant System	Revision 40
PB 02 MSFK00000417	P & ID Auxiliary Coolant System	Revision 17

Procedures

OI-152	HX-12A&B CCW Heat Exchanger Data Collection Performed on April 8, 2001	Revision 1
OI-152	HX-12A&B CCW Heat Exchanger Data Collection Performed on October 17, 1999	Revision 0

Specifications

Job Number 5887	Component Cooling Water Heat Exchanger Specification Sheet	February 24, 1992, Revision 3
	CCW Heat Exchanger Installation-Operation-Maintenance Instructions	3-17-80
000499	Maintenance Instructions for Residual Heat Exchanger S.P.I.N. WISACAHRS-1 & 2	Revision 0
S.P.I.N. WISACAHRS-1 & 2	Residual Heat Removal Heat Exchanger Specification Sheet	Revision 0

Technical Specification

3.7.8	Service Water System	Unit 1 Amendment 201, Unit 2 Amendment 206

FSAR

Section 9.6.1	Service Water System Design Basis	06/01
Table 14.3.4-5	Analysis Assumptions Used for Case 3	06/01

Miscellaneous

	Nuclear Oversight Fourth Quarter 2001 Assessment Report for Point Beach	January 30, 2002
RCE 01-041 (CR 01-2178)	Root Cause Evaluation for Unit #2 Manual Trip Due to Decreasing Pump Bay Level (Traveling Water Screens Plugged with Large Influx of Small Fish)	July 27, 2001

1R08 Inservice Inspection

CR 01-1406	VT Data Sheet Lost	April 23, 2001
CAP002706	Ultrasonic Test Equipment Did Not Have MT&E Stickers Attached	March 28, 2002
CR 01-1759	1993 ISI Report Errors	May 14, 2001
CR 01-1985	Modification Closeout Discrepancies	June 6, 2001
CAP002707	Incorrect Information on Primary ISI Isometric Drawings	March 28, 2002
CR 99-3117	Weaknesses Noted in Performance Based Audits of ISI Activities	December 3, 1999
CAP003061	ISI Operating Experience Sharing Between NMC Plants Needs Improvement	April 26, 2002
NRC 2001-0013	2000 Inservice Inspection of Pt. Beach Unit 2, Outage U2R24	March 23, 2001
NDE-451	Visible Dye Penetrans Examination	November 30, 2001
NDE-350	Magnetic Particle Examination	March 15, 2002

1R11 Licensed Operator Qualifications

Scenario Number SG-0106	Steam Leak to ECA 2.1	Revision 0
SG-0106	Steam Leak to ECA 2.1, Instructors Comments	May 23, 2002
Emergency Planning Implementation Procedure 1.2	Emergency Classification	Revision 35

1R12 Maintenance Rule Implementation

NPM 2002-0161	2001 Annual Report for the Maintenance Rule	March 28, 2002
NPM 2002-0175	2001 Annual Report for the Maintenance Rule	April 3, 2002
NPM 2001-0251	2000 Annual Report for the Maintenance Rule	March 26, 2001
	Maintenance Rule Functional List for 125 VDC [Volts-Direct Current] Electrical	May 10, 2002
	Maintenance Rule Performance Criteria, 125 VDC	July 8, 1998
	Work Orders for 125 VDC With M, F or C in MPFF Field Initiated or Completed Between 4/1/2000 and 5/1/2002	

1R13 Maintenance Risk Assessment and Emergent Work Evaluation

	E-1 Report for T01A1 (Work Week Schedule)	Run Date - May 20, 2002
	E-1 Report for T05A1	Run Date - June 17, 2002
NP 10.3.7	On-Line Safety Assessment	Revision 5
NP 10.3.7	On-Line Safety Assessment	Revision 6
	Weekly Core Damage Risk Profile (Safety Monitor)	May 19 - 25, 2002 June 16 - 22, 2002
	Safety Monitor Core Damage Frequency Calculation	May 19 & 21, 2002 June 18 - 20, 2002
	E-1 Report for T01A1 (Work Week Schedule)	Run Date - June 24, 2002
	Weekly Core Damage Risk Profile (Safety Monitor)	June 24 - 28, 2002
	Safety Monitor Core Damage Frequency Calculation	June 24 - 28, 2002

1R15 Operability Evaluations

Event Notification 38819	Identification of an Unanalyzed Condition That Had the Potential To Significantly Degrade Plant Safety	April 1, 2002

Retraction of Event Notification 38819	Identification of an Unanalyzed Condition That Had the Potential To Significantly Degrade Plant Safety	May 17, 2002
Engineering Evaluation 2002-0016	MAAP [Modular Accident Analysis Program] Analysis To Support Reduced Charging Flow (CAP002701)	May 9, 2002
CAP002701	Inadequate Nitrogen Capacity On Site To Support CVC [Chemical and Volume Control] Pump Operation for Appendix R	March 28, 2002
AR 2976	Problems With OD [Operability Determination] 98-0164	April 22, 2002
OD 98-0164	HELB Outside Containment	Revision 9
OD 98-0164	HELB Outside Containment	Revision 10
OD 01-1559	Unit 2 CFC [Containment Fan Coil] Fans Reduce Flow Rates	Revision 1
Calculation 2001-0011	CFC Air Flow Requirements	Revision 0
AR 3172	Accident Fan Air Flows Determined Less Than 38,500 CFM [Cubic Feet per Minute] While Performing SEM 7.14	May 4, 2002
FSAR Section 6.3	Containment Air Recirculation System	June 2001
FSAR Section 14.3.2	Large Break Loss of Coolant Accident Analysis	June 2001
AR 28420	G-02 Ran At Full KW [Kilowatt] Loading and Above Full Load KVAR [Kilovolt Ampere Reactive] On Two Separate Occasions	June 8, 2002
AR 28360	G-02 Failure During the Performance Of TS-82 Extended Run	June 1, 2002
Circuit Breaker Trip Curves	Square D Company, Thermal-Magnetic/Magnetic Only Molded Case Circuit Breakers, 100A Frame, Tripping Curves	September 1991
CAP028490	U-1 Cross Over Steam Dump DV-4 May Not Fully Open	June 16, 2002

10 CFR 50.59/72.48 Screening	TRM [Technical Requirements Manual] 3.7.6, Turbine Overspeed Protection, Revision 1	June 16, 2002
CT-27153	Overspeed Analysis for Wisconsin Electric Power Company Point Beach 1 & 2	Revision 0 October 12, 1996
Discussion Paper, Point Beach Design Basis Document Program	Turbine Overspeed Protection & Crossover Steam Dump Operability	August 1994
FSAR Appendix T	Turbine Overspeed Protection	June 2001
FSAR Section 10.1	Steam and Power Conversion	June 2001
OPR-000019	1P-29 Turbine-Driven Aux Feed Pump Outboard Bearing Description	June 13, 2002
CAP028464	Degradation of Unit 1 Turbine Driven Aux Feed Pump Outboard Bearing	June 13, 2002
	Vibration Analysis Report, 1P-29 TDAFP [Turbine Driven Auxiliary Feedwater Pump], 1V ips	May 4, 2002
	Vibration Analysis Report, 1P-29 TDAFP, 1H ips	May 4, 2002
	Acceleration Analysis Report, 1P-29 TDAFP, GOV H ips	May 4, 2002
	Acceleration Analysis Report, 1P-29 TDAFP, GOV H ips	February 7, 2002
	Acceleration Analysis Report, 1P-29 TDAFP, 1A ips	May 4, 2002
	Acceleration Analysis Report, 1P-29 TDAFP	February 7, 2002
	Lubrication Oil Analysis Report, 1-P-29-T Outboard Turbine Bearing	May 21, 2002
	Ferrogram Analysis Report, PBNP [Point Beach Nuclear Plant] 1-P-029T Aux Feed Pump Outboard Bearing	May 4, 2002

1R16 Operator Workarounds

Operator Work Around Summary	Summary List	March 25, 2002
OWA 0-00R-004 RMS	DC Bus Over/Under Voltage Alarms Received During Routine Starts of Unit 1 & 2 Safeguards Pumps	March 25, 2002
Plant Modification 01-074	Add Time Delays to Battery Charger and DC Bus Voltage Alarm Circuits	June 21, 2002
IWP 01-074	Battery Charger and DC Bus Voltage Alarm Time Delays	June 26, 2002

1R19 Post-Maintenance Testing

Work Order 0205569	G05 Battery Cleaning	
PC 29	Monthly Gas Turbine and Auxiliary Diesel Load Test	Revision 34
WO 0206367	Reactor Coolant Loop 'B' Cold Leg to CVCS [Chemical Volume and Control System) Letdown Isolation	May 8, 2002
Temporary Modification 02-023	Freeze Seal Installation Upstream of 2RC-427	May 8, 2002
NP 7.4.3	Post-Maintenance and Modification NDE [Non-Destructive Evaluation] Requirements for Power Piping	Revision 2
RMP 9010	Freeze Seal Installation and Removal	Revision 1
P&ID 541F445, Sheet 1	Reactor Coolant System, Point Beach Nuclear Plant Unit 2	Revision E
Indication Disposition Report 7P-028	Rigid Support Evaluation, Component RC-2501R-10-PS	May 9, 2002
WO 9938029	Oil Change on P-035A-M Electric Fire Pump	May 27, 2002
WO 9926764	Remove and Replace Upper End Bell of P-035A-M Electric Fire Pump	May 27, 2002
WO Work Plan for WO 9926795	Perform Maintenance on 480 Volt DB-50 Switchgear Breaker for P-035A-M Electric Fire Pump	May 13, 2002
WO 9926795	Perform Maintenance on 480 Volt DB-50 Switchgear Breaker for P-035A-M Electric Fire Pump	May 27, 2002

WO 0202275	Complete Repack of P-035A-M Electric Fire Pump	June 19, 2002
CAP028293	Proper PMT When G05 Building is Powered Down	May 22, 2002
0-PT-FP-003	Monthly Electrical Motor-Driven Fire Pump Functional Test	Revision 1
IT 11	Spent Fuel Pool Cooling Pumps (Quarterly and Biennial)	Revision 22
WO 9930154	Open [Spent Fuel Pool] Heat Exchanger for Eddy Current Testing.	June 11, 2002
CAP028553	HX-13A Spent Fuel Pool Cooler Tube Degradation	June 20, 2002
FSAR Section 9.9	Spent Fuel Cooling & Filtration	June 2001
WO 9949340	Replace 1LT-618, Unit 1 T-12 Component Cooling Water Surge Tank Level Transmitter	
RMP 9037	Diesel Fire Pump Engine Inspection	Revision 0
0-PT-FP-002	Monthly Diesel Engine-Driven Fire Pump Functional Test	Revision 1
Design Basis Document DBD-T-40	Fire Protection /Appendix R	March 31, 1998
CAP 028627	Documentation Deficiencies Identified In a Completed (Reviewed) Work Order	June 28, 2002

<u>1R20</u> <u>Refueling and Outage Activities</u>

ORT 3B	Safety Injection Actuation With Loss of Engineered Safeguards AC (Train B)	Revision 33
ORT 3A	Safety Injection Actuation With Loss of Engineered Safeguards AC (Train A)	Revision 34
Temporary Procedure Change (TCN) 2002-225	Safety Injection Actuation With Loss of Engineered Safeguards AC (Train B)	April 12, 2002
Safety Evaluation (SCR) 20025-0148	ORT 3B Safety Injection Actuation With Loss of Engineered Safeguards AC (Train B), OM 3.26, AOP-18 and 19 Series	April 12, 2002
Operational Manual (OM) 3.26	Use of Dedicated Operators	Revision 7

Weekly Core Damage Risk Profile	Unit 1, Week Beginning 4/14/02, S08B2/E-1a	
NP 10.3.6	Outage Safety Review and Safety Assessment	Revision 9
Contingency Plan	Containment Orange Path Contingency Action Plan, 1st Orange Path for April 16, 2002, Unit 2	Revision 0
Contingency Plan	Containment Orange Path Contingency Action Plan, 2st Orange Path for April 18, 2002, Unit 2	Revision 1
	U2R25 Critical Path Schedule	April 14, 2002
	U2R25 Outage Safety Assessment, Key Safety Functions, April 12 - 19, 2002	April 10, 2002
	U2R25 Outage Safety Assessment, Key Safety Functions, April 12 - May 7, 2002	
OP [Operating Procedure] 3C	Hot Standby to Cold Shutdown	Revision 87
OP 7A	Placing Residual Heat Removal System In Operation	Revision 41
OI 105	RCS Heat Up/Cooldown Plotting	Revision 8
IT 04D	RHR Valve Exercise Test for Operation or Shutdown Unit 2	Revision 4
Temporary Change 2002-0237	Revise Initial Condition 4.5 To Allow Performance of OP-7A/IT 04D With (1) One RCP Danger Tagged OOS	April 16, 2002
Safety Evaluation Screening 2002-0151	Revise IT-04D Initial Conditions to Permit Performance With A Single RCS Loop Operable	April 16, 2002
AR 2843	TSAC [Technical Specification Action Conditions] Entry in Mode 4 for RCS Loop Inoperable	April 14, 2002
NRC Inspection Manual Part 9900	Technical Guidance: Maintenance - Voluntary Entry into Limiting Conditions for Operation Action Statements to Perform Preventative Maintenance	January 17, 2002
RMP 9224	Removal and Replacement of Containment Equipment Hatch	Revision 1
Point Beach Form (PBF) 1562	PBNP Shutdown Safety Assessment and Fire Condition Checklist	April 30, 2002

0-TS-EP-001	Weekly Power Availability Verification, Completed April 29, 2002	Revision 3
Tag Series 5 4.16 KV A-6 EM Rev0-1	4.16 KV [Kilovolt] Bus Switchgear (Safeguards), Perform 2A06 Bus Inspection	April 22, 2002
CL 5C	Spent Fuel Pool Cooling and Refueling Water Circulating Pump Normal Operation Valve Lineup	Revision 9
AR 3011	Valves Found Out of Position	April 24, 2002
	Chemistry Sample Results for the Spent Fuel Pool, Unit 2 Reactor Coolant System Hot Leg, and Refueling Water Storage Tank	April 10 to April 30, 2002
Engineering Evaluation 2001-0034	Source Range NI [Nuclear Instrument] Channel Check Criteria	Revision 4
AR 2833	2N-32 Channel Check Unsat	April 13, 2002
FSAR Section 14.1	Core and Coolant Boundary Protection Analysis	June 2001
FSAR Section 7.6.1	Nuclear Instrumentation System	June 2001
OP 1B	Reactor Startup	Revision 44
Refueling Procedure 1C	Refueling	Revision 48
P&ID M-224	Post-Accident Containment Ventilation System, Point Beach Nuclear Plant Unit 1 and 2	Revision E
CL 2A	Defueled to Mode 6 Checklist, Completed April 23, 2002	Revision 1
Temporary Procedure Change 2002-0273	CL 2A, Defueled to Mode 6 Checklist	April 23, 2002
CL 20	Post-Outage Containment Closeout Inspection (U-2)	May 5, 2002
CL 20	Post-Outage Containment Closeout Inspection (U-2)	May 9, 2002
AR 3260	Unapproved Material Found During Post Containment Closeout Unit 2	May 10, 2002
NP 8.4.15	Protective Coating Program	Revision 2
	Report on Containment Coating Assessment Point Beach Nuclear Plant - Unit 2	April 29, 2002

Westinghouse Evaluation	Reload Safety Evaluation Point Beach Unit 2 Cycle 26	Revision 2
Reactor Engineering Surveillance Procedure 4.1	Initial Criticality and ARO [All Rods Out] Physics Testing	Revision 16
Westinghouse Technical Manual 1440-C344	Vertical Steam Generator, Instructions for Wisconsin Electric Power Company, Point Beach Unit 1, Two Creeks, Wisconsin	July 1983
Westinghouse Technical Manual 1440-C370	Vertical Steam Generator, Instructions for Wisconsin Electric Power Company, Point Beach Unit 2, Two Creeks, Wisconsin	July 1996
AR 3112	Steam Generator Narrow Range Level Uncertainty at Lower Temperatures	April 30, 2002
Engineering Evaluation 2001-0032	Parametric Values	Revision 2
Engineering Evaluation 2001-0032	Parametric Values	Revision 3
Safety Screening 2002-0130	Definition of Steam Generator Operable for Decay Heat Removal by Natural Circulation in Mode 5 With Loops Filled	April 4, 2002
Point Beach Form (PBF) 0026p	Procedure Feedback Request for IT 03D, RHR Valve Exercise Test for Operation or Shutdown Unit 1	Revision 4
PBF 0026p	Procedure Feedback Request for IT 04D, RHR Valve Exercise Test for Operation or Shutdown Unit	Revision 4
PBF 0026p	Procedure Feedback Request for IT 03C, HHSI [High Head Safety Injection] Check Valve Exercise Test in Cold Shutdown - Unit 1	Revision 4
PBF 0026p	Procedure Feedback Request for IT 04C, HHSI Check Valve Exercise Test in Cold Shutdown - Unit 2	Revision 5
PBF 0026p	Procedure Feedback Request for IT 03B, LHSI [Low Head Safety Injection] Valve Exercise Test in Cold Shutdown Unit 1	Revision 7

PBF 0026p	Procedure Feedback Request for IT 04B, LHSI Valve Exercise Test in Cold Shutdown Unit 1	Revision 6
PBF 0026p	Procedure Feedback Request for Technical Specification (TS) Test TS 30, High and Low Head Safety Injection Check Valve Leakage Test Unit 1	Revision 23
PBF 0026p	Procedure Feedback Request for TS 31, High and Low Head Safety Injection Check Valve Leakage Test Unit 2	Revision 23
PBF 0026p	Procedure Feedback Request for ORT 3B, Safety Injection Actuation With Loss of Engineering Safeguards AC (Train B) Unit 2	Revision 33
PBF 0026p	Procedure Feedback Request for ORT 3B, Safety Injection Actuation With Loss of Engineering Safeguards AC (Train B) Unit 1	Revision 32
PBF 0026p	Procedure Feedback Request for ORT 3A, Safety Injection Actuation With Loss of Engineering Safeguards AC (Train A) Unit 1	Revision 35
PBF 0026p	Procedure Feedback Request for ORT 3A, Safety Injection Actuation With Loss of Engineering Safeguards AC (Train A) Unit 2	Revision 34
PBF 0026p	Procedure Feedback Request for Point Beach Form 2034 Control Room Daily Logsheet Unit 1	Revision 50
PBF 0026p	Procedure Feedback Request for Point Beach Form 2034 Control Room Daily Logsheet Unit 2	Revision 51
PBNP-IC-25	Steam Generator Narrow Range Level Instrument Uncertainty and Setpoint Calculation	Revision 0
PBNP-IC-26	Steam Generator Narrow Range Level Scaling Calculation	Revision 0
Temporary Procedure Change 2002-0373	SEP 3.0, Loss of All AC Power - Unit 2	Revision 13
Safety Evaluation Screening 2002-0216	SEP 3.0 Loss Of All AC Power To A Shutdown Unit	May 23, 2002
Engineering Evaluation 2001-0032	Parametric Values	Revision 4

Temporary Procedure Change 2002-0372	SEP 3.0, Loss of All AC Power - Unit 1	Revision 12
PBNP Background Document	Alternate Core Cooling, Summary for SEP 1.1	Revision 4
SEP 1.1	Alternate Core Cooling	Revision 5
2ICP 4.003-2	Steam Generator Level Transmitters Outage Calibration	Revision 4
SEP 3.0	Loss of All Power To a Shutdown Unit - Unit 1	Revision 12
PBNP Background Document	Loss of All Power To a Shutdown Unit	Revision 7
PBNP EOP Setpoints	SG [Steam Generator] Narrow Range	Revision 2
SEP 3.0	Loss of All Power To a Shutdown Unit - Unit 2	Revision 13
Point Beach Form 1562	Point Beach Shutdown Safety Assessment and Fire Condition Checklist, Unit 2 U2R25 Refueling Outage	May 12 through April 14, 2002
Point Beach Form 2035	Control Room Daily Logsheet - Unit 2	Revision 52
Point Beach Form 2034	Control Room Daily Logsheet - Unit 1	Revision 51
Design and Installation Guidelines Manual DG-I01	Instrument Setpoint Methodology	Revision 3
Instrumentation, Systems, and Automation Society	ISA-RP67, Section 6, Calculating Instrument Channel Uncertainties	April 2, 2000

<u>1R22</u> <u>Surveillance Testing</u>

TCN 2002-225	Safety Injection Actuation With Loss of Engineered Safeguards AC (Train B)	April 12, 2002
SCR 2002-0148	ORT 3B Safety Injection Actuation With Loss of Engineered Safeguards AC (Train B)	April 12, 2002
ORT 3B	Safety Injection Actuation With Loss of Engineered Safeguards AC (Train B) Unit 2	Revision 33

TCN 2002-219	Safety Injection Actuation With Loss of Engineered Safeguards AC (Train A)	April 12, 2002
SCR 2002-0150	ORT 3A (Rev. 34) Safety Injection Actuation With Loss of Engineered Safeguards AC Without G-02	April 12, 2002
ORT 3A	Safety Injection Actuation With Loss of Engineered Safeguards AC (Train A) Unit 2	Revision 34
IT 04D	RHR Valve Exercise Test for operation or Shutdown Unit 2	Revision 4
SCR 2002-0237	RHR Valve Exercise Test for Operation or Shutdown Unit 2, Revise Initial Condition 4.5 to Allow Performance of OP-7A/IT04D With (1) One RCP Danger Tagged OOS [Out of Service]	April 14, 2002
FSAR Section 9.2	Residual Heat Removal (RHR)	June 2001
FSAR Section 14.3	Large Break Loss-of-Coolant-Accident Analysis, Table 14.3.2-10, Plant Operating Range Allowed By The Best-Estimate Large Break LOCA Analysis (Point Beach Nuclear Plant)	June 2001
Operational Manual (OM) 3.26	Use of Dedicated Operators	Revision 7
Procedure Feedback Form	OM 3.26, Use of Dedicated Operators	May 2, 2002
TS 36	Local Leak Test of Containment Purge Valves Unit 2	Revision 15
TS 10A Binder	Local Leak Rate Test Results for TS-36, Penetration V-1	May 9, 2002
IT 295B	Overspeed Test Turbine-Driven Auxiliary Feedwater Pump, Refueling Interval, Unit 2	Revision 11
DBD 01	Auxiliary Feedwater System	Revision 1
TCN 2002-330	Overspeed Test Turbine-Driven Auxiliary Feedwater Pump	May 6, 2002
RMP 9200-1	Station Battery D-05 Discharge Tests and Equalizing Charge	Revision 8
	BCT-2000 Battery Load Test Report, D-05	April 3, 2002
WO 9940482	Conduct Performance Test Per RMP 9200-1	
FSAR Section 8.7	125 VDC Electrical Distribution System (125V)	June 2001

1ICP 02.013	4.16KV Undervoltage Matrix Relays 31 Day Surveillance Test,	Revision 5
2ICP 02.013	4.16KV Undervoltage Matrix Relays 31 Day Surveillance Test,	Revision 6
DBD-22	4160 VAC System	February 5, 1997

1R23 Temporary Plant Modifications

TM# 02-002	Temporary Replacement of Service Water Pump Column for P-032D	February 1, 2002
CAP001649	Seismic Qualification of Service Water Pump Column Bolting Questioned	October 6, 1999

2OS1 Access Control to Radiologically Significant Areas

Action Request Items

CAP002618	Abnormal Radiation Levels Found on F-38 Laundry Tank Filter During Resin Flush	March 19, 2002
CAP002840	Locked HRA Boundary at Upper Cavity Left Unguarded and Unlocked	April 14, 2002
CAP003003	Radiation Worker Entered Pipe Way #3 on Wrong RWP	April 24, 2002

Self-Assessments

NPM 2002-0084	Review of the Radiation Program for the Year 2001	February 20,2002
SA-RP-01-01	RP Radiation Monitoring System	October 15, 2001

20S2 ALARA Planning and Control

Procedures

NP 1.6.10	Pre-and Post-Job Briefs	Revision 1
NP 4.2.1	Plant ALARA Program	Revision 6
NP 4.2.29	Source Term Reduction Program	Revision 3
RWP 02-205	Install/Remove Temporary Shielding in Containment	Revision 0
RWP 02-206	Install/Remove Temporary Shielding in PAB	Revision 0
RWP 02-216	Replace Rx [Reactor] Head O-Rings	Revision 0

RWP 02-225	RCP Maintenance	Revision 0
RWP 02-227	Containment High Radiation Area Maintenance	Revision 0
RWP 02-234	Regenerative Heat Exchanger Cubicle Maintenance	Revision 0
RWP 02-250	Containment Accident Fan Modification	Revision 0
RWP 02-263	Letdown Piping Support Modification	Revision 0
RWP 02-265	RV [Rector Vessel] Head-Shroud Removal/Replacement	Revision 0
RWP 02-267	RV Head Asbestos Abatement, Visual Inspection, and Associated Activities	Revision 0
RWP 02-268	RV Head UT [Ultrasonic Testing] Inspection (Under Head)	Revision 0
RWP 02-269	RV Head- Initial under Head Surveys and Decontamination	Revision 0
RWP 02-270	RV Head Install New Insulation	Revision 0
RWP 02-273	Westinghouse Rx Head Measurements (Under Head)	Revision 0
RWP 02-275	Repair 2SI-867B	Revision 0
Miscellaneous Data		
2001-0006	ALARA Review Package, Steam Generator (S/G) Eddy Current and Tube Plugging	May 2, 2001
2001-0007	ALARA Review Package, S/G Handhold Cover Removal and Replacement/Sludge Lancing Operations	May 4, 2001
2002-0005	ALARA Review Package, Remove/Replace RCP	April 11, 2002
2002-0006	ALARA Review Package, Inservice Inspections	April 11, 2002
2002-0007	ALARA Review Package, Insulation Removal/Replacement	April 12, 2002
2002-0008	ALARA Review Package, Scaffold Construction	April 11, 2002

2002-0009	Replace Operator and Change Packing Configuration (Replace Valve Trim) on 2CV-296	April 11, 2002
2002-0010	ALARA Review Package, Modification of "C" and "D" Accident Fan Coolers	April 11, 2002
2002-0012	ALARA Review Package, Excess Letdown Piping Modification	April 11, 2002
2002-0013	ALARA Review Package, Rx Vessel Head Asbestos Abatement and Visual Inspection	April 12, 2002
2002-0014	ALARA Review Package, Under Rx Vessel Initial Surveys and Decontamination	April 12, 2002
2002-0015	ALARA Review Package, Under Rx Vessel Head UT Inspection	April 12, 2002
2002-0016	ALARA Review Package, Remove and Install Vertical Sections of the CRDM Ventilation Shroud of the RV Head.	April 12, 2002
	ALARA Review Status Log Sheet	April 11, 2002
	Daily Dose Totals, Gamma and Neutron	April 1-23, 2002
	"On-Track", Daily U2R25 Outage Bulletins	April 22-25, 2002
	Operations Log Entries Report	April 24-25, 2002
	Outage Plan of the Day	April 22-23, 2002
	Outage Status Report	April 23, 2002
	Point Beach Nuclear Plant, Three Year Rolling Average Graphic Chart, 1976-2001	
	Point Beach Unit 2, Refueling Outage Total Dose (TLD) Graphic Chart 1976-2001	
	Point Beach Total Dose (TLD) Graphic Chart 1974-2001	
	Post-job ALARA Review, Fuel Transfer Cart Maintenance	April 12, 2002
	Point Beach Nuclear Plant, Pregnancy Declaration Form	Revision 2

	Pre-outage Estimates and Actual Outage (To Date of Inspection) RWP Reviews of Exposure Data, Spreadsheet, RWPs #02-200 to 02-272	April 24, 2002
	Radiation Protection Outage Schedule	April 22-29, 2002
	TEDE [Total Effective Dose Equivalent] ALARA Evaluation, Upper Cavity Decontamination	April 12, 2002
	TEDE ALARA Evaluation, Lower cavity Decontamination	April 12, 2002
	TEDE ALARA Evaluation, Upper Internals Lift Rig Inspection	April 12, 2002
	TEDE ALARA Evaluation, Cavity Seal Ring Demolition	April 12, 2002
	TEDE ALARA Evaluation, Reactor Head Underneath Work	April 14, 2002
	U2R25 Dose chart	April 22, 2002
	U2R25 Outage Personal Contamination Event (PCE) Details Summary Sheet, with Attached Whole Body Count Data Sheets (4-23-02)	April14-23, 2002
	U2R25 RWP Log sheet	
	U2R25 Work Activities Receiving ALARA Reviews	

Self -Assessments

NPM 2000-0358	Unit 1, Primary Chemistry Refueling Summary (U1R25), Summary of U1C26 Forced Outage (U1C26FO)	April 13, 2000
NPM 2001-0442	Unit 2, Primary Chemistry Refueling Summary (U2R24)	June 14, 2001
NPM 2001-0807	Unit 1, Primary Chemistry Refueling Summary (U1R26)	December 7, 2001
NPM 2002-0210	Special ALARA/Waste Minimization Meeting #02-02 to Review the Reactor Head Inspection	April 18, 2002
	Estimated Radiation Dose for U2R25	March 16, 2002

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

Action Request items

CAP004974	RP Tech Error During Sampling	February 2, 2001
CR 01-0469	Air Sampler Head Installed Backwards	February 14, 2001
CAP013789	Purge Sampling Responsibility	April 10, 2001
CR 01-1809	Rad Checks on Unit 1 Service Water Overboard Missed	May 18, 2001
CAP000940	RMS Liquid Monitors Out of Service	August 23, 2001
CAP002381	DAM-3 Alarms	March 4, 2002
CAP002458	DAM-2 Failure	March 8,2002
CAP002831	1RE-229 Failed During Monitor Tank Discharge	April 13, 2002
CAP007920	Spurious RMS Alarms During Heavy Rains	April 24, 2002
CAP003300	Error in Dilution Flow Entered on Liquid Permit	May 15, 2002

Procedures

CAMP 015	Sampling and Monitoring of Service Water System Components	Revision 0
CAMP 030	Manual Preparation of Batch Liquid and Gaseous Effluent Discharge Release Permits with the Following Data Sheets:	January 2001 through May 2002
	Data Sheet 1 - Liquid Discharge Permit Evaluation Data Sheet;	.
	Data Sheet 2 - PBNP Permit for Batch Discharge of Liquid Radioactive Waste;	
	Data Sheet 4 - Gas Decay Tank Discharge Evaluation Data Sheet;	
	Data Sheet 5 - PBNP Permit for Gaseous Discharge of Gas Decay Tank;	
	Data Sheet 7 - Gaseous Discharge of Containment Data Evaluation Sheet;	
	Data Sheet 8 - PBNP Batch Release Gaseous Discharge Containment Vent Permit;	

	Data Sheet 9 - Containment Vent Permit;	
	Data Sheet 10 - Gaseous Discharge of Containment Evaluation Data Sheet;	
	Data Sheet 11 - PBNP Batch Release Gaseous Discharge Containment; and	
	Data Sheet 12 - Containment Purge Permit	
CAMP 031	Preparation of Batch Liquid and Gaseous Effluent Permits Using RETSCODE Software with the Following Data Sheets:	Revision 1
	Data Sheet 1 - Permit for Batch Discharge of Liquid Radioactive Waste;	
	Data Sheet 3 - PBNP Batch Release Gaseous Discharge Containment Vent Permit;	
	Data Sheet 4 - Containment Vent Permit; and	
	Data Sheet 6 - RMS Assessment Worksheets	January 2001 through May 2002
CAMP 100.1	Technical Specification Chemistry Surveillance Requirements	Revision 17
CAMP 101	Daily Routine Sampling Schedule for Operating, Refueling, or Shutdown Units	Revision 58
CAMP 102	Gas Decay Tank Sampling Guidelines	Revision 16
CAMP 103	Continuous and Batch Release Composite Samples	Revision 14
CAMP 106	Interlaboratory Radiological Cross Check Procedure	Revision 9
CAMP 300	MCA Efficiency Calibrations	Revision 13
CAMP 601	Primary Auxiliary System Sample Points	Revision 8
FT - 13	NUCON International, Inc., Acceptance for In-place Testing, Air Flow Rate and Charcoal Absorber Tests	Revision 6
FT - 13	NUCON International, Inc., Acceptance for In-place Testing, Air Flow Rate and Charcoal Absorber Test Results for Unit 1 & 2 Containment Purge, Service Building Exhaust, Chem Lab Vent , Auxiliary Building Exhaust, Spent Fuel Pool, Control Room, and TSC.	Revision 6

HPCAL 3.0	Radiation Monitoring System Calibration, Fixed Background Subtraction Adjustments and Air Ejector Alert Setpoint Calculation	Revision 14
HPCAL 3.1	Liquid Monitor Calibration Procedure	Revision 27
HPCAL 3.1	Liquid Monitor Calibration Procedure, Test Results for Detectors #Unit 1&2 RE-216 and 216B, #1&2 RE-219 and 219B, #1&2 RE229 and 229B, RE-218 and 218B, RE-220, RE-223, RE-230 and 230B.	Revision 27
HPCAL 3.12	Condenser Air Ejector Monitor Calibration	Revision 22
HPCAL 3.12	Condenser Air Ejector Monitor Calibration, with Test Results for Detectors #Unit 1&2 RE-215, RE-225.	Revision 22
HPCAL 3.13	Steam Generator Blowdown Tank Monitor (1&2 RE-222) Calibration	Revision 12
HPCAL 3.4	SPING Calibration Procedure	Revision 26
HPCAL 3.4	SPING Calibration Procedure, with Test Results for SPINGs #21, 22, 23, and 24.	Revision 26
HPCAL 3.6	PNG Calibration Procedure	Revision 22
HPCAL 3.6	PNG Calibration Procedure, with Test Results for Detectors # Unit 1 & 2 RE-211and 211B, and #1 & 2 RE-212,	Revision 22
HPCAL 3.8	Stack Exhaust Monitor Calibration	Revision 16
HPCAL 3.8	Stack Exhaust Monitor Calibration, with Test Results for Detectors # RE-214, RE-221, and RE-224.	Revision 16
HPIP 11.50	Filter Testing	Revision 16
HPIP 11.50	Filter Testing, with Test Results from 5-18-01	Revision 16
HPIP 11.54	Control Room F-16 Filter Testing	Revision 4
HPIP 11.54	Control Room F-16 Filter Testing with Test Results from 5-18-01	Revision 4
HPIP 11.52	HEPA and Charcoal Filter Administrative Controls	Revision 2
ODCM	Off-Site Dose Calculation Manual	Revision 14
OI 140	Standard Radioactive Batch Liquid Release	Revision 5

OI 9C	Containment Venting and Purging	Revision 50
OP 9D	Discharge of Gas Decay Tank(s)	Revision 17
TRM [Technical Requirements Manual] 4.1	PBNP Off-Site Dose Calculation Manual (ODCM)	Revision 0
TRM 4.4	Radioactive Effluents Controls Program	Revision 0
TRM 4.10	Ventilation Filter Testing Program (VFTP)	Revision 0
RECM	Radiological Effluent Control Manual	Revision 3

<u>Self -Assessments</u>

NPM 2001-0205	Chemistry Self-assessment: Chemistry QA/QC Program	March 31, 2001
A-P-01-05	2Q2001 Nuclear Oversight Report, “Primary Water Chemistry Monitoring Program”	December 7, 2001
2002-002-3-012	Nuclear Oversight Observation Report, “Radioactive Waste Processing, (1) Radioactive Effluent Sampling and Analysis Quality Control, (2) Radioactive Gaseous and Liquid Effluent Treatment and Monitoring System, and (3) Radioactive Gaseous and Liquid Effluent Processing System Maintenance.	May 22, 2002

<u>Miscellaneous Data</u>

	Control Charts for Chemistry Lab Detectors #1, 2, and 3	April 2002 to May2002
	Control Charts for TSC Count Room Detector (#4) and Portable Analyzer (#5)	April 2002 to May 2002
	Annual Monitoring Report 2001, Nuclear Management Company, LLC, Point Beach Nuclear Plant. January 2001 through December 31, 2001	April 2002
	“NMC Today,” Team Notes for Kewaunee/Point Beach	May 30, 2002
ODCM	Summary of Changes, Revision 14	November 15, 2001
PBF-4028g	Daily Radiation Protection Sampling Checklist, Monday -Friday	Revision 12
PBF-413a	Background Change Calculation Worksheet	Revision 6
PBF 413b	Air Ejector Monitor (RE-215) Alert Setpoint Calculation Worksheet	Revision 1

PBF-3070	Monthly PBNP “Potentially Contaminated Steam Releases for Units 1&2"	January 2001 through May 2002
PBF-3194	Point Beach Nuclear Plant, Interlab Radiological Crosscheck Data Sheets, Detectors #1-4	February 2001 through June 2002
PBF - 4074	Beach Drain Sample Collection Data, with Non-routine Radiological Analysis Results	January 2001 though April 2002
RECM	Summary of Changes, Revision 3	November 15, 2001
	Gamma Spectrum Analysis Results for Steam Generator Blowdown Filter Outlet Sample	June 4, 2001
	Liquid Waste Discharge Permits	January 2001 through May 28, 2002
	Gaseous Waste Discharge Permits	January 2001 through May 2002
RWP 02-042	NRC Walkdowns/Inspection of Liquid and Gas Waste Processing Systems	Revision 0

3PPI Physical Protection - Access Authorization (AA) Program

	Fitness-For-Duty, Semi-Annual Performance Data Report	March 1, 2002
	Continual Behavioral Observation Program - NMC	

3PP2 Physical Protection - Access Control

Point Beach Security Administrative Procedure (PBSAP) 2.1	Walk-Through Metal Detector Testing	September 14, 2000
PBSAP 2.3	Explosive Detector Testing	April 26, 2001
PBSAP 2.4	X-Ray Device Testing	April 26, 2001
PBSAP 1.4	Security Locks, Keys, and Combinations	May 29, 2001
	Corrective Action Program - Security Related Issues	May 2001 - June 2002
	Point Beach Security System Tracking	April 2001 - April 2002
	Security Force Incident Reports	April 2001 - May 2002

02-02-3-009	Nuclear Oversight Observation Report	April - June 2002
	Nuclear Oversight Quarterly Report	3rd Quarter 2001

3PP4 Physical Protection - Security Plan Changes

	Independent Spent Fuel Storage Installation Plan	July 25, 2001
	Security Training and Qualification Plan	July 25, 2001

4AO1 Performance Indicator Verification

CAP001254	Misinterpretation of an NRC Performance Indicator	November 2, 2001
	Quarterly Train Unavailability Reports	2001 to 2002
CAP028516	February Monthly Operating Report Contained Error in Number of Reactor Critical Hours	June 18, 2002
NEI 99-02	Regulatory Assessment Performance Indicator Guideline	Revision 1
	Selected Reactor Operator and Shift Manager Logs	January 1, 2001 to March 31, 2002
FSAR Section 6.2	Safety System Injection System (SI)	June 2000
	PI Data Summary Report Q1/2002, Units 1 & 2 Unplanned Scrams per 7,000 Critical Hours	April 10, 2002
	Scrams with Loss of Normal Heat Removal Performance Indicator Coordinator Data Sheets	May 2, 2002
NP 5.2.16	NRC Performance Indicators	Revision 4
Action Request Items		
CAP 000768	Dose Errors in ODCM	June 15, 2001
CR 01-0116	Ownership of Rad Effluent Program	July 2, 2001
CAP 001418	Offsite Dose Calculation Manual (ODCM) Commitment Changes	November 29, 2001
CAP 002332	ODCM Program Requirement Not Met	February 27, 2002

Procedures

NP 5.2.16	NRC Performance Indicators	Revision 4

Miscellaneous data

	Monthly Dose Summary, Total Liquid Dose and Noble Gas Dose, Performance Indicator Data.	CY 2001 and First Quarter 2002

4A03 Event Follow-up

CAP002245	Safety Injection Pump, Fails During OI-163 Performance	February 20, 2002
Root Cause Evaluation Report	Unit 2 Safety Injection Pump "Gas Bound" During Routine Preventive Maintenance	May 17, 2002

4A05 Other

7570001	Point Beach Nuclear Plant Remote Visual Examination Record, Reactor Pressure Vessel Closure Head	
NDE-757	Visual Examination For Leakage Of Reactor Pressure Vessel Closure Head Penetrations	March 15, 2002
	Unit 2 RV CRDM Nozzle Inspection Plan	March 25, 2002
(PBNP) NRC-02-029	Response To NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation And Reactor Coolant Pressure Boundary Integrity"	April 2, 2002
NRC 2002-0029	Revised Response To NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation And Reactor Coolant Pressure Boundary Integrity"	April 18, 2002

LIST OF INFORMATION REQUESTED

The following information is needed to be delivered to Region III by November 23, 2001, to support the biennial “Heat Sink Performance” inspection, Procedure 71111.07. Please provide for the following heat exchangers (HXs) [Component Cooling Heat Exchanger, HX-12A; Unit 1 Residual Heat Removal Heat Exchanger, PB1 HX-11A; and Waste Gas Heat Exchanger, HX-48A-1]:

1. Copy of the two most recently completed tests confirming thermal performance of each HX. Include documentation and procedures that identify the types, accuracy, and location of any special instrumentation used for these tests. (e.g., high accuracy ultrasonic flow instruments or temperature instruments). Include calibration records for the instruments used during these tests. Include drawings showing the piping configurations and flowpaths for normal operation and testing for the HXs. Also indicate where the instruments used for the tests were located. Describe the measures to ensure proper fluid mixing for temperature considerations.
2. Copy of the evaluations of data for the two most recent completed tests confirming the thermal performance of each HX.
3. Copy of the calculation which establishes the limiting (maximum) design basis heat load which is required to be removed by each of these HXs.
4. Copy of the calculation which correlates surveillance testing results from these HXs with design basis heat removal capability (e.g., basis for surveillance test acceptance criteria).
5. The clean and inspection maintenance schedule for each HX. For the last two clean and inspection activities completed on each HX, provide a copy of the document describing the inspection results. Provide HX performance trending data tracked for each HX.
6. Provide a copy of the document which identifies the current number of tubes in service for each heat exchanger and the supporting calculation which establishes the maximum number of tubes which can be plugged in each HX. Provide a copy of the document establishing the repair criteria (plugging limit) for degraded tubes which are identified in each HX.
7. Copy of the as-built HX specification sheets. Also provide the design specification and heat exchanger data sheets for each HX. Copy of the vendor and component drawings for each HX. Copy of the vendor and operating manuals for each HX.
8. Provide a list of issues with a short description documented in your corrective action system associated with these HXs in the past three years. Provide a list of issues with a short description documented in your corrective action system associated with the ultimate heat sink, especially any loss of heat sink events and any events or conditions that could cause a loss of ultimate heat sink.

If the information requested above will not be available, please contact Gerard O’Dwyer as soon as possible at (630) 829-9624 or E-mail - gfo@NRC.gov.

LIST OF INFORMATION REQUESTED

The following information is needed to be available onsite June 10, 2002, to support the biennial “Heat Sink Performance” inspection, Procedure 71111.07. Please provide for the following heat exchangers (HXs) [Component Cooling Heat Exchanger, HX-12A and Unit 1 Residual Heat Removal Heat Exchanger, PB1 HX-11A]:

1. Copy of the two most recently completed tests confirming thermal performance of each HX. Include documentation and procedures that identify the types, accuracy, and location of any special instrumentation used for these tests. (e.g., high accuracy ultrasonic flow instruments or temperature instruments). Include calibration records for the instruments used during these tests. Include drawings showing the piping configurations and flowpaths for normal operation and testing for the HXs. Also, indicate where the instruments used for the tests were located. Describe the measures to ensure proper fluid mixing for temperature considerations.

2. Copy of the evaluations of data for the two most recent completed tests confirming the thermal performance of each HX.

3. Copy of the calculation which establishes the limiting (maximum) design basis heat load which is required to be removed by each of these HXs.

4. Copy of the calculation which correlates surveillance testing results from these HXs with design basis heat removal capability (e.g., basis for surveillance test acceptance criteria).

5. The clean and inspection maintenance schedule for each HX. For the last two clean and inspection activities completed on each HX, provide a copy of the document describing the inspection results. Provide HX performance trending data tracked for each HX.

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8. Provide a list of issues with a short description documented in your corrective action system associated with these HXs in the past three years. Provide a list of issues with a short description documented in your corrective action system associated with the ultimate heat sink, especially any loss of heat sink events and any events or conditions that could cause a loss of ultimate heat sink.

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