U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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| Licenses Nos: | DPR-24; DPR-27 |
| Report No: | 50-266/97026(DRP); 50-301/97026(DRP) |
| Licensee: | Wisconsin Electric Power Company, WEPCO |
| Facility: | Point Beach Nuclear Plant, Units 1 and 2 |
| Location: | 6612 Nuclear Road<br>Two Rivers, WI 54241-9516 |
| Dates: | December 1, 1997, through January 20, 1998 |
| Inspectors: | F. Brown, Senior Resident Inspector<br>P. Louden, Resident Inspector<br>L. Collins, Resident Inspector, Quad Cities Station<br>M. Kunowski, Project Engineer |
| Approved by: | J. McCormick-Barger, Chief<br>Reactor Projects, Branch 7 |

## EXECUTIVE SUMMARY

Point Beach Nuclear Plant, Units 1 and 2
NRC Inspection Report No. 50-266/97026(DRP); 50-301/97026(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. In addition to routine inspection procedure aspects, this inspection period included a review of selected NRC and licensee-identified problems and the corrective actions taken. The report covers a seven-week inspection period by the resident inspectors.

### Operations

- The Unit 1 high voltage station auxiliary transformer failed on January 8, 1998. The operators responded well, and safety-related equipment worked as expected. The failure was caused by insulation degradation which was attributable to inoperable bus duct strip heaters. An automatic fast bus transfer did not occur as designed due to a design error. The licensee performed a thorough and insightful review of this event and identified a fundamental weakness in the use of some aspects of Technical Specifications (TSs) by licensed operators. The NRC review identified inappropriate procedural adherence standards regarding the use of emergency and abnormal operating procedures. Two violations were identified. (Section O1.2)

- The licensee's use of the temporary information tag program was generally acceptable. However, the inspectors identified several instances where tags were left hanging on equipment longer than intended, and examples of the use of temporary information tags on abandoned in-place radioactive waste equipment instead of danger tags, which would have been more appropriate. (Section O2.2)

- Corrective actions for problems with several procedures and for the premature securing of cooling water to a reactor coolant pump were reviewed and found to be complete and thorough. (Section O3)

### Maintenance

- Two completed corrective actions were reviewed in the maintenance area. One, for a foreign material exclusion issue, was determined to be narrowly focused, and the other was appropriate, but the corrective action was not accurately documented in the licensee's issue tracking database (NUTRK). The licensee indicated that a broad evaluation was being performed in the area of foreign material exclusion under a separate action from that reviewed by the inspectors. (Sections M4 and M8)

### Engineering

- The inspectors concluded that the licensee had misapplied the TS requirements relating to the performance of American Society of Mechanical Engineers (ASME) Section XI inservice testing associated with pressure tests for Class 2 and 3 systems. However, the licensee effectively identified and corrected the problem. (Section E1.1)

- The engineering department conducted a thorough root cause evaluation of problems associated with the installation of the wrong tubing in a reactor vessel level indication system modification. (Section E2.1)

- Test control deficiencies associated with the containment accident fan coolers had been identified in 1995, and new tests were to have been performed shortly after the August 1997 restart of Unit 2. However, the new tests had not been performed as of the end of November 1997. One violation was identified. (Section E8.1)

Plant Support

- The inspectors determined that the health physics department was effective in addressing an adverse trend regarding workers failure to wear proper dosimeters. (Section R4.1)

- Based on the results of a close-out inspection of the Unit 2 containment, the licensee identified the need to perform additional cleaning and improve future close-out cleanliness standards. (Section R4.2)

## Report Details

### Summary of Plant Status

Unit 1 was placed on-line at the beginning of this inspection period, and remained at 98 percent rated power until an end-of-life power coastdown was started on January 17, 1998. Power was limited to 98 percent because of instability in the electro-hydraulic turbine controller at the higher electrical output resulting from the newly installed low pressure turbines. A partial loss of offsite power event occurred on January 8, 1998. This event is discussed in Section O1.2.

Unit 2 remained in a mid-cycle outage throughout this period while modifications were made to the auxiliary feedwater system. Dual unit operation was precluded pending completion of these modifications.

## I. Operations

### O1 Conduct of Operations

#### O1.1 General Comments (IP 71707)

The inspectors conducted frequent reviews of ongoing plant operations. The inspectors observed Unit 1 and Unit 2 control room shift turnovers and observed control room operations on a daily basis. Operator attentiveness to control boards and response to alarms were good. The conduct of shift briefings, which was inconsistent between crews in the past, improved.

#### O1.2 Failure of High Voltage Station Auxiliary Transformer (HVSAT)

a. Inspection Scope (IP 71707)

The inspectors reviewed the licensee's response to a loss of the Unit 1 HVSAT "1X03."

b. Observations and Findings

Description of the Event

The Unit 1 HVSAT, "1X03," isolated at 7:05 p.m. on January 8, 1998, when protective circuitry sensed a fault. At the time, Unit 1 was operating at 98 percent power and Unit 2 was in cold shutdown. A severe winter storm (freezing temperatures, 10 inches of snow, and 42-mile-per-hour wind) was in progress. This isolation removed the normal source of power from the H02 (Unit 1) and H01 (the Unit 1 and Unit 2 cross-tie and gas turbine output) 13.8-kiloVolt (kV) buses. Automatic relaying should have closed the H03 (Unit 2) to H01 cross-connect breaker, "H52-31," which would have resulted in off-site power being supplied to all three sections of the 13.8-kV bus through the Unit 2 HVSAT, "2X03." This automatic function failed to operate, resulting in a loss of power to H01 and H02. Bus H02 provides normal power to the Unit 1 low voltage station auxiliary transformer, "1X04," which supplies power to the non-safety-related 4.16-kV switching buses "1A03" and "1A04." The Unit 1 safety-related 4.16-kV buses, "1A05" and "1A06," are normally fed from 1A03 and 1A04, respectively. The three operable emergency diesel generators (EDGs) started on loss of voltage signals for 1A05 and 1A06, and the Unit 1 EDGs loaded to the assigned buses. The normal feed breakers between 1A03 and 1A05, and between 1A04 and 1A06, opened to separate non-safety-related buses from the EDGs. The safety-related 4.16-kV and 480-volt systems were de-energized only for the period of time required for the EDGs to start, come up to speed, and load onto the 4.16-kV buses.

Station auxiliary loads, including feedwater, reactor coolant, and circulating water pumps, were not affected by the loss of the HVSAT because they were being fed from the unit generator-supplied auxiliary transformer, "1X02." Output from the unit generator was not affected because it connects to the switchyard distribution bus via the main transformer, "1X01." Charging and letdown isolated when 1A05 and 1A06 were de-energized. Charging pumps were manually restarted after the EDGs re-energized the two safety-related buses. Two of the four station battery chargers were being fed through 1A05 and 1A06 when these buses lost power. The safety-related batteries carried the loads on the two affected direct current (DC) buses when the battery chargers lost power. The primary and secondary portions of the plant remained stable throughout this event and the event recovery. The isolation breakers for one of the four off-site 345-kV feed lines opened when 1X03 isolated. The other three off-site 345-kV lines were not affected.

Initial operator response focused on restoring power to the affected 13.8-kV and 4160-volt buses. The response was complicated by the absence of procedures for recovering the 13.8-kV bus. Operators exercised proper restraint in waiting until procedural guidance was developed before taking action. The station gas turbine generator, "G05," was started at 9:21 p.m., 2¼ hours after 1X03 was lost. This re-energized buses H01, H02, 1A03, and 1A04. Breaker H52-31 was closed manually at 10:50 p.m., paralleling G05 with off-site power from transformer 2X03. These actions were delayed while plant staff reviewed the condition of buses H01 and H02, and breaker H52-31 to ensure that re-energization would not result in initiation of additional faults or unintended isolations. Safety-related bus 1A06 was reconnected to its normal power source, 1A04, at 12:44 a.m. on January 9, 1998, 5 hours and 40 minutes after it lost this source. Safety-related bus 1A05 was reconnected to its normal power source, bus 1A03, at 4:18 a.m. on January 9, 1998. The associated EDGs were secured after off-site power was supplied to each bus.

Initiating Equipment Failure and Equipment Response

The licensee's event investigation team determined that this event was initiated when a phase-to-phase short circuit occurred in the bus ductwork between transformer 1X03 low voltage output connections and the low voltage isolation breaker, "H52-05," on bus H02. This short developed due to water saturated and moisture damaged insulation. The root cause of this condition was determined to be the failure of strip heaters installed in the bus ductwork and the H52-05 breaker cubicle. The function of these heaters was to prevent condensation of moisture inside the ductwork and breaker cubical. The heaters were found to be inoperable because of a failed ground fault indicating, 20-ampere circuit breaker. The breaker was located in a lighting panel and was coded as 120-volt alternating current (AC) lighting. A corrective maintenance work order had been initiated in August 1996 to repair the breaker. The work order was classified as "minor maintenance," a classification which excluded it from system reviews performed during 1997. The work order was still in the minor maintenance backlog on January 8, 1998. The inspectors and licensee subsequently reviewed the minor maintenance backlog records. No additional examples of inappropriately designated minor maintenance items were identified. The licensee also performed thermography of the other bus ductwork exposed to outdoor weather and determined that all strip heaters were functioning properly. A periodic review of all strip heater breakers was also implemented as an immediate corrective action.

The non-safety-related bus cross-connect function of breaker H52-31 failed to work as expected. The licensee's incident investigation team determined that this failure was caused by a design error in the non-safety-related portion of modification package MR9116*B, which had installed new control switches for the breakers. The new switches were a different part number and had different contact logic than the original switches. The engineers who performed and reviewed the modification work did not identify that the contact logic of the new switches defeated the fast bus transfer function when the breaker control switch was in its normal position (auto). The engineers also failed to specify post-modification testing for the fast bus transfer function. The lack of a periodic test of the 13.8-kV fast bus transfer had been identified by the resident inspectors and discussed in Inspection Report (IR) 50-266/96003(DRP); 50-301/96003(DRP), but the licensee had not taken any action to verify the operability of the non-safety-related function.

The inspectors reviewed the available plant parameter computer system alarm records, the station and unit logs, the applicable sections of the Final Safety Analysis Report (FSAR), the emergency operating procedures (EOPs) and abnormal operating procedures (AOPs), and the design basis documentation for the electrical distribution systems and determined that all other plant equipment operated as expected, with the minor exception of a failed synchronous check relay on one instrument bus. Power to the instrument bus was not interrupted.

Operator Response

Following the loss of 1X03, the operators entered AOP 18A Unit 1, "Train 'A' Equipment Operation," Revision 4, and AOP 18B Unit 1, "Train 'B' Equipment Operation," Revision 2. The inspectors compared the unit "Narrative Log" entries to the sequence of steps in AOPs 18A and 18B and found that the logs did not indicate that equipment was returned to service in the procedurally specified sequence. The inspectors discussed this finding with the incident investigation team. The licensee reviewed the use of AOPs 18A and 18B, and concluded that the operators had performed as trained, in that procedure steps were followed in the order specified. The licensee also informed the inspectors that Procedure OM [Operations Manual] 3.7, "Emergency Operating Procedure Use and Adherence," Revision 4, authorized the performance of EOP and AOP steps out-of-sequence and the addition of non-specified steps, as long as the procedure intent was not changed. Procedure OM 3.7 specified that these actions were not considered procedure deviations. The inspectors reviewed the information provided by the licensee and concluded that the operators had performed AOPs 18A and 18B in accordance with their procedures and training. The inspectors noted that the blanket authorization to perform steps out-of-sequence and to perform non-specified steps was inconsistent with the upper tier licensee Procedure NP [Nuclear Business Unit Procedure] 1.1.4, "Procedure Use and Adherence," Revision 1, and with TS 15.6.8.3 which required approval by the cognizant group head (duty shift superintendent in operations) and one of the duty and call superintendents for changes to procedures. This blanket authorization was, therefore, inappropriate to the circumstances, and a violation (VIO 50-266/97026-01(DRP); 50-301/97026-01(DRP)) of 10 CFR Part 5[illegible] [illegible]endix B, Criterion V.

Use of TSs

On January 9, 1998, the inspectors requested that the licensee clarify an apparent inconsistency in the application of TS 15.3.7.A.1 and TS 15.3.0. Specifically, the licensee had entered TS 15.3.0 (initiation of actions to shut down a reactor when conditions not allowed by TS existed) on January 9, 1998, when G05 was shutdown for a short period to remove ice from the compressor intake and 1X03 was still out-of-service. Logged entry into TS 15.3.0 had been made for the loss of power to the two affected battery chargers on January 8, 1998, but TS 15.3.0 had been exited when the battery chargers were re-energized at 7:15 p.m., which was prior to G05 being placed in-service at 9:21 p.m. The licensee informed the inspectors that the on-shift crew had erred in not remaining in TS 15.3.0 until G05 was placed in-service, and that the licensee's incident investigation team, which had been formed to review the loss of off-site power event, would perform a complete review of TS use during the event.

On January 13, 1998, the licensee amended the 10 CFR 50.72 notification for this event to include information on the failure to enter TS 15.3.0 for three conditions: loss of 1X04 (required for electrical distribution operability by TS 15.3.7.A.1.c), loss of 1X[illegible] without G05 being in-service (required for electrical distribution operability by TS 15.[illegible].A.1.b), and loss of normal power supply to 1A05 and 1A06 concurrently (required for electrical distribution operability by TS 15.3.7.A.1.i). Technical Specification 15.3.0.B requires that action be initiated within one hour to place the affected unit in hot shutdown within seven hours of entering this specification. Fortuitously, all conditions requiring entry into TS 15.3.0.B were corrected prior to the expiration of the seven hours, but the failure to recognize the applicability of TS 15.3.0.B and initiate action to shut down within one hour was a violation (VIO 50-266/97026-02(DRP); 50-301/97026-02(DRP)) of TS 15.3.0.

The incident investigation team interviewed many licensed senior reactor operators (SROs) who did not understand the requirement to enter TS 15.3.0 in cases where the TS contained ambiguous wording for establishing LCO operability requirements and specific permissible conditions did not apply. In the case of electrical distribution, TS 15.3.7.A.1 specified conditions required prior to taking a unit critical. Technical Specification 15.3.7.B.1 provided permissible conditions which modified the requirements of TS 15.3.7.A.1 when a unit was at power. Many SROs did not recognize that TS 15.3.7.A.1 established basic LCO operability requirements for a unit anytime it was critical, and that if TS 15.3.7.A.1 was not satisfied, and no permissible condition in TS 15.3.7.B.1 applied, then entry into TS 15.3.0 was required. The licensee initiated immediate action, including briefing each operating crew and placing a "required-reading" entry in the control room Operations Notebook to address this fundamental shortcoming in use of the TSs. Long-term corrective actions, including changes to the initial and requalification programs, were being considered at the end of the inspection period.

c. Conclusions

The Unit 1 HVSAT failed on January 8, 1998. The operators responded well, and safety-related equipment worked as expected. The failure was caused by insulation degradation which was attributable to inoperable bus duct strip heaters. An automatic fast bus transfer did not occur as designed due to a design error. The licensee performed a thorough and insightful review of this event and identified a fundamental weakness in the use of some aspects of TSs by licensed operators. The NRC review identified inappropriate procedural adherence standards regarding the use of EOPs and AOPs. Two violations of NRC requirements were identified.

**O2 Operational Status of Facilities and Equipment**

O2.1 Verification of Safety System Valve Positions (IP 71707)

The inspectors independently verified valve positions for the Unit 1 safety injection and containment spray systems. The inspectors noted that all valves were positioned according to controlled drawings and were in the proper position to perform the intended engineered safety features function. The inspectors noted that significant amounts of boric acid had crystallized around the inner bearing seal area of the safety injection pumps. The inspectors called this to the attention of an SRO who had the seal area rinsed with deionized water. The SRO further stated that a review of the expectations for auxiliary operators to clean seal leaks would be performed.

O2.2 Control of Posted Plant Information

a. Inspection Scope (IP 71707)

The inspectors reviewed the licensee's program for identifying, posting information pertaining to, and repairing equipment deficiencies. The specific proceduralized program reviewed included the use of temporary information tags and posted plant drawings as described in OM 5.4.4 "Control of Posted Plant Information," Revision 2.

b. Observations and Findings

Procedure OM 5.4.4 described the method which ensured that the dissemination of plant information was appropriately authorized, documented, and reviewed. The use of temporary information tags was discussed in Section 7 of OM 5.4.4. The temporary information tag program was required to be reviewed quarterly by operations department staff for applicability and accuracy.

The inspectors independently walked down the temporary information tag locations in the plant and reviewed the two most recently completed audits of the tag logs. The inspectors had three observations regarding the temporary information tag program:

- The current temporary information log contained 11 items which were greater than 2 years old. The inspectors asked licensee management whether 2-year-old items met the conditions to be part of the temporary information program. Station management stated that the intent of the temporary information program was to identify circumstances which would last for only a short duration and that it was not appropriate to include 2-year-old items in the program. Licensee management stated that the use of the temporary information tag program would be reviewed.

- During a temporary tag walkdown, the inspectors noted that a tag dated March 1995 had been placed on the Unit 1 flux mapping control panel. Directly below the tag was a permanent label on the panel which contained the same wording as the temporary information tag. Further review revealed that the permanent label had been installed in July 1997, and that the temporary information tag should have been removed. Noteworthy was that during the last two quarterly reviews (both dated after the permanent label was installed), the temporary tag was documented as still applicable and verified to be in-place. The inspectors determined that the operators' attention-to-detail during the performance of the quarterly reviews was lacking.

- The third inspector observation involved temporary information tags which were placed on the waste evaporator system. The wording on the tags informed the reader that the equipment was abandoned in-place and that the valves were serving as isolation boundaries. The inspectors questioned licensee management regarding the appropriateness of using the temporary information program for this application. This particular case would have been more appropriately handled through the danger tag program.

c. <u>Conclusions</u>

The inspectors concluded that generally the temporary information tag program was implemented effectively. However, the inspectors identified uses of temporary tags which were not within the intended scope of the program.

**O3 Operations Procedures and Documentation**

As part of the inspection into the licensee's corrective action program, the inspectors reviewed the responses to three self-identified problems documented through the problem identification process. The inspectors' focus was on the adequacy of the root cause evaluations and the effectiveness of corrective actions.

O3.1 <u>Corrective Actions to Address Discrepancy Between Procedures (IP 71707)</u>

The licensee identified a discrepancy between Operations Procedure (OP) 3C, "Hot Shutdown to Cold Shutdown," Revision 66, and OP 7A "Placing Residual Heat Removal System in Operation," Revision 33, and documented the problem in Condition Report (CR) 97-0852. Procedure OP 3C, Step 4.12.2, required the operators to align the residual heat removal (RHR) system for operation, with the reactor coolant temperature between 370 degrees Fahrenheit (°F) and 380 °F. The initial condition requirements for OP 7A, however, stated that the reactor coolant temperature was to be less than 350 °F. A control operator noted this problem and the OP 3C Procedure was revised. The Final Safety Analysis Report (FSAR) further stated that the RHR system is aligned for decay heat removal <u>after</u> the reactor coolant temperature had been reduced below 350 °F.

The inspectors reviewed the revised OP 3C and noted that steps in the procedure were changed to ensure that the reactor coolant temperature was below 350 °F prior to removing the RHR system from its low head safety injection alignment. The inspectors determined that the actions taken addressed the problem and that a good questioning attitude was displayed by the operator who originated the concern.

O3.2 Root Cause Evaluation Addressing Premature Securing of Component Cooling Water to Unit 2 "B" Reactor Coolant Pump

a. Inspection Scope (IP 71707)

The inspectors reviewed the root cause evaluation and corrective actions implemented to address problems identified with the premature securing of the component cooling water (CCW) supply to the Unit 2 "B" reactor coolant pump (RCP).

b. Observations and Findings

Operations personnel initiated a condition report (CR) on July 24, 1997, after the CCW supply to the Unit 2 RCP was secured and danger tagged while the RCS temperature was above 370 °F. This was done in preparation to secure the "B" RCP for pump seal work; however, securing cooling water with the RCS above 370 °F was undesirable in that pump seal damage would be accelerated had seal water supply been lost. The duty shift supervisor erroneously made the decision to secure the CCW supply, even though the Unit 2 control operator questioned the decision given current plant conditions.

Based on the results of the event investigation, the licensee determined that the root cause was non-conservative decision making on the part of the duty shift supervisor. Contributing factors included programmatic concerns regarding the lack of an oversight issue manager, inadequacies with the use of notes and precautions in the danger tag procedure, and a failure to develop an overall work plan with scheduled event sequences.

To address these concerns, the operations manager conducted a training session to review this event and emphasize conservative decision making, conflict resolution, modifications to the work control process, and a complete revision of the danger tagging procedure (NP 1.9.15).

The licensee also initiated a restructuring of the entire work control process which was ongoing at the conclusion of the inspection. The licensee stated that one of the work control process changes will be to establish work-week managers who will be responsible for maintaining oversight of ongoing work activities.

c. Conclusions

The inspectors determined that the root cause evaluation performed to address the concerns described above was thorough and identified the appropriate root causes and contributing factors. The corrective actions taken by the operations department were also deemed to be effective.

O3.3 Evaluation of the Adequacy of Reactor Coolant Pump Breaker Racking Requirements

The inspectors reviewed the licensee's evaluation of a level "D" (lowest priority) CR which described concerns regarding the accuracy of breaker positioning instructions for RCP breakers. Specifically, the concerns involved operations procedures which were overly restrictive for maintaining breaker positions within the seismic qualifications.

Operations department staff determined that no problems existed with the procedure and that the documented concern would be placed in the procedure "tickler" file for consideration during the next procedure revision. The inspectors considered these actions acceptable, but noted that the use of the station's more formal, procedure feedback program process might have provided greater assurance that the issue would be resolved in a timely manner.

## O5 Operator Training and Qualifications

### O5.1 Licensed Operator Examination Security

a. Inspection Scope (IP 71707)

The inspectors reviewed the circumstances surrounding a licensee-identified concern regarding licensed operator examination security during 1997 requalification testing.

b. Observations and Findings

Operations department training staff discovered five remedial requalification study guides on a former employee's personal local area network (LAN) directory on December 19, 1997. The existence of the study guides on an unsecured computer created the concern that the annual requalification examination had been compromised. The issue was documented in CR 97-4125 and a root cause investigation was initiated by the licensee.

The 1997 requalification examination was administered on March 3 to March 21 and August 4 to September 26, 1997. The former employee worked for the operations training department and was part of the 1997 licensed operator requalification examination team. One of his assigned duties was to develop the remedial study guides.

Members of the licensee's root cause team, which reviewed the matter, provided the inspectors with the following information:

- The examination question bank was a closed database. The questions contained within the database were not accessible for self-study use by operators.
- The LAN directory, which contained the remediation study material, could only be accessed by three individuals at the site (LAN managers and computer staff.)
- The material contained in the study guides was not of sufficient detail to allow an individual to directly ascertain the content of a specific question.
- Test scores did not improve following the time frame that the remediation material was placed on the unsecured computer.
- Employees involved with the requalification examination were briefed and bound by a security agreement for the duration of the testing.

- The former employee, whose directory contained the remediation guides, was interviewed by the license. The individual indicated that he tightly controlled the study guides and he did not leave his computer unattended while the information was in the directory.

Based on the above information, the licensee concluded that an examination compromise had not occurred and that the potential for a compromise was not very probable. The inspectors agreed with this conclusion.

c. Conclusions

The inspectors determined that a compromise of the 1997 annual license requalification examination had not occurred.

**O8 Miscellaneous Operations Issues**

O8.1 (Closed) Licensee Event Report (LER) 50-266/96011; 50-301/96011: "Delta T" Trip Setpoints Not Reduced In Accordance With TS. On November 21, 1996, the licensee discovered that "delta T" trip setpoints were not reduced in accordance with TSs during the Unit 1, cycle 24 startup. Technical Specification 15.3.10.B.1.c required that the overpower and overtemperature "delta T" setpoints be reduced if a measured hot channel factor exceeded the full power limit and it could not be subsequently demonstrated within 24 hours that the limits were met. This LER addressed deficiencies in the clarity of the TS in effect in November 1996. The licensee submitted a TS amendment request which the NRC Office of Nuclear Reactor Regulation approved on January 16, 1997. The failure to perform the "delta T" trip setpoint adjustments when it was determined that full power hot channel factors would have been exceeded based on the measured values at 28 percent power was considered a violation of TS 15.3.10.B.1.c. However, this non-repetitive, licensee-identified and corrected violation was considered a non-cited violation (NCV 50-266/97026-03(DRP); 50-301/97026-03(DRP)) consistent with Section VII.B.1 of the NRC Enforcement Policy.

O8.2 (Closed) LER 50-266/96006; 50-301/96006: Emergency Power Out of Service Coincident With Opposite Train Service Water Pump Out of Service. This LER involved cross-train removal of a service water pump coincident with the out-of-service of the opposite standby emergency power train. Specifically, while one of the Train B EDGs was undergoing a monthly surveillance test, a Train A service water pump (P-32B) start switch was placed in the pull-to-lock position. This condition, which was not allowed by TSs, lasted for approximately 30 seconds. The control operator realized that an operability question existed with the Train B EDG being tested. The operator then returned the service water pump switch to the AUTO position.

The licensee's investigation identified deficiencies in the procedure for voluntary entry into limiting conditions for operations (Nuclear Procedure 10.1) and the duty and call superintendent guidance (DCS 3.1.7) regarding interpretation of the TS. Both procedures were enhanced to call attention to the service water pump cross-train issue.

The inspectors reviewed the licensee's actions including an evaluation of the adequacy of the current voluntary entry into limiting conditions for operations procedure (Nuclear Procedure 10.1.1, Revision 7) and the DCS 3.1.7 guidance. The inspectors noted that clear guidance was contained within each of these documents which should preclude recurrence of this type of event. This item is closed.

O8.3 (Closed) LER 50-266/96003; 50-301/96003: Plant Operation Outside of Design Basis of the Low Temperature Overpressure Protection System (LTOP). On June 21, 1996, the licensee identified that a procedure allowed operation with two high pressure safety injection (SI) pumps available while the reactor coolant system (RCS) was in the water-solid condition and RCS temperature was below the LTOP-enable temperature of 360 °F. This was in conflict with the design basis for LTOP which assumed a worst case mass input transient of one SI pump discharging to the RCS while the system was solid and pressure relief provided by one power-operated relief valve. The licensee stated that there were no instances where both SI pumps discharged to the RCS with LTOP enabled. The licensee subsequently revised the procedure to reflect the design basis and requested a license amendment to also align TS 15.3.15, on LTOP, with the design basis. In addition, based on a reevaluation, the licensee requested that the LTOP-enable temperature be lowered to 355 °F. The license amendment with the revised temperature limit was subsequently issued February 20, 1997.

## II. Maintenance

### M4 Maintenance Staff Knowledge and Performance

M4.1 Foreign Material Exclusion Control During Polar Crane Wiring Changeout

a. Inspection Scope (IP 62707)

The inspectors reviewed the effectiveness of licensee corrective actions taken to address an incident involving failure to adequately implement foreign material exclusion (FME) techniques.

b. Observations and Findings

Licensee root cause report number 97-028 addressed an occurrence documented in CR 97-1768 which involved the loss of FME controls on June 2, 1997. A team of maintenance workers were replacing lights on the Unit 2 polar crane. During the work, a metal ferrule nut from a wire for one of the lights fell from the crane into the lower transfer canal.

Based on the results of the event investigation, the licensee determined that the root cause was poor worker practices and ineffective self-checking. The workers erected FME barriers; however, the barriers did not provide sufficient controls for an item as small as a wire ferrule.

The inspectors determined that better self-checking could have possibly prevented the event from occurring. In addition, the adequacy of the FME barriers erected and the quality of the FME governing procedure were considered contributing factors. These latter factors were not included in the licensee's investigation. The licensee informed the inspectors that a separate root cause evaluation was being performed for programmatic aspects of FME control.

c. Conclusions

The licensee's corrective actions for the loss of FME control event were narrowly focused on human performance deficiencies and did not address any associated programmatic problems.

**M8 Miscellaneous Maintenance Issues**

M8.1 (Closed) LER 50-266/96001: Inadvertent Engineered Safety Feature (ESF) Actuation in Train B Due To DC System Ground. On April 5, 1996, maintenance activities were underway to locate a ground associated with the Train B DC electrical system. A test rig used to locate the ground inadvertently actuated the Train B ESF circuitry resulting in the starting of all Train B safety injection equipment. The cause of the actuation was an inadequate ground detection technique. The use of a light bulb test rig along with the ground in the system completed a circuit which provided enough current to actuate the SI circuitry.

The licensee stated in the LER that an evaluation would be performed to identify better industry ground detection techniques. This effort was completed in 1996 and the review team recommended that a test configuration used at one of the baseline plants be implemented. The licensee's issue tracking database (NUTRK) described the recommendation and indicated that the issue would be closed following the acceptance of the proposed new ground detection technique.

The inspectors discussed the corrective actions with the cognizant maintenance department supervisor. The inspectors were told that the corrective actions described in the tracking database were not the actual actions taken. Electrical maintenance had purchased a state-of-the-art ground testing meter different than what was described in the NUTRK database. The inspectors had no technical concerns regarding the use of the purchased ground detection equipment. However, the information contained within the NUTRK database system for documented closure of the item was inaccurate. This item is closed.

## III. Engineering

**E1 Conduct of Engineering**

E1.1 Failure to Conduct American Society of Mechanical Engineers (ASME) Section XI Pressure Tests

a. Inspection Scope (IP 37551)

The inspectors reviewed the circumstances surrounding the licensee identified problem involving the failure to perform ASME Section XI 40-month pressure tests on Class 2 and Class 3 systems.

b. Observations and Findings

During a review of the pressure test program, engineering personnel identified that the requir..d 40-month inservice inspection pressure test for the following systems had not been accomplished: the Unit 1 boric acid storage tanks and associated piping, the air start system for the G01 and G02 EDGs, waste gas system tanks and piping, and the Unit 2 refueling water storage tank.

The deficiency in the pressure test program was first identified in September 1996 and documented in CR 96-840. Engineering management decided that the test could be delayed until an ongoing pressure test program upgrade was completed. On November 4, 1997, the pressure test issue was re-visited. The pressure test engineer determined that CR 96-840 did not address operability of the affected systems. This deficiency was documented in CR 97-3730 and an operability determination was performed. The systems were determined to be operable, and the licensee decided that for those systems that were currently out-of-service, tests would be completed prior to returning them to service.

C. January 2, 1998, the licensee determined that TS 15.4.2.B.1 had historically been misinterpreted. Technical Specification 15.4.2.B.1 states, in part, that inservice inspection of ASME Code Class 1, Class 2, and Class 3 components shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda. Historically, the failure to meet the Section XI required tests was viewed as a nonconformance and was not regarded as a missed TS surveillance test. The licensee concluded that failure to meet the Section XI Code requirements should have been treated as a missed TS surveillance test.

The licensee identified the deficient pressure tests based on a review of potentially affected systems. The systems were declared inoperable and TS 15.4.3 was entered for a missed surveillance test. All tests (except for G02-related systems) were subsequently conducted within the 24-hour allowance provided in TS. The licensee planned to perform the G02 air start system test as part of the return-to-service for the EDG which was out-of-service for an upgrade modification.

The failure to perform the inservice tests required by ASME Section XI is considered a violation of TS 15.4.2.B.1. However, this non-repetitive, licensee-identified and corrected violation was considered a non-cited violation (NCV 50-266/97026-04(DRP); 50-301/97026-04(DRP)) consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

The inspectors concluded that the licensee had misapplied the requirements of the TS relating to the performance of ASME Section XI inservice testing. However, the licensee effectively identified and corrected the problem. One non-cited violation was identified.

## E2 Engineering Support of Facilities and Equipment

E2.1 Review of Corrective Actions For a Change to a Reactor Vessel Level Indication System (RVLIS) Modification Made Without Using the Change Request Process

a. Inspection Scope (IP 37551)

The inspectors reviewed the licensee's corrective actions taken to address problems associated with changes made to the RVLIS modification without using the modification change request process.

b. Observations and Findings

The subject event involved the improper authorization for construction personnel to install different size tubing than specified in the modification design package. Construction personnel requested to install ¼-inch tubing rather than the design drawing specified ½-inch tubing. A construction supervisor authorized the use of the smaller tubing, but did not recognize the seismic requirements inherent in the ½-inch design specification. The responsible design engineer noted the discrepancy during a post-installation walkdown. The problem was documented in CR 97-3457 and root cause analysis 97-103.

The inspectors determined that the root cause evaluation was thorough, with probing evaluations into the causes of the problem. Some of the corrective actions were not complete at the end of the inspection period and will be reviewed during a future inspection. These corrective actions will be tracked under Violation 50-266/97021-02(DRP); 50-301/97021-02(DRP), which was issued to describe a violation regarding the inoperability of the containment hatch interlock. The licensee's proposed corrective actions for this violation include addressing weaknesses in the work control procedures related to implementation of proper design control.

c. Conclusions

The inspectors concluded that the licensee performed a thorough root cause evaluation into problems associated with the RVLIS modification.

## E8 Miscellaneous Engineering Issues

E8.1 (Closed) Unresolved Item (URI) 50-266/95011-02(DRP); 50-301/95011-02(DRP): Inadequate Testing of Containment Accident Fan Coolers. In Inspection Report (IR) 50-266/95011(DRP); 50-301/95011(DRP), the inspectors documented a potential operability concern regarding the Unit 1 1HX-15D containment accident fan cooler. Data from performance test PC-56, "Containment Accident Recirc Heat Exchanger Performance Monitoring Unit 2," Part 2, Revision 5, was used to calculate a fouling factor for the heat exchanger. When the fouling factor of 0.0014 was used to calculate the heat removal rate for the cooler, the licensee determined that the heat removal rate was less than the 50 million British thermal units per hour specified in the FSAR. The engineering staff chose to disregard the data due to uncertainties associated with the test, including inappropriate test conditions and instrument inaccuracies.

The inspectors further identified in IR 50-266/95011(DRP); 50-301/95011(DRP) that other nonconservative values for service water temperature and flow rate, in addition to the nonconservative fouling factor of 0.0014, were used in the containment accident fan cooler heat removal calculation and other calculations used to justify cooler operability.

The inspectors classified these issues as an unresolved item and requested that the licensee submit a formal written evaluation to the NRC. A response, dated January 19, 1996, was submitted in which the licensee concluded that the test results were inconclusive due to test inaccuracy. The licensee stated that in addition to service water flow instrumentation inaccuracies, test results could vary based on the number of service water pumps in operation and service water temperatures. The licensee's evaluation concluded that the fan cooler had remained operable. This operability evaluation was based on a special improved accuracy test and a computer analysis of the summer of 1995 flow and water temperature conditions. In addition, routine and preventive maintenance was performed on the containment fan coolers to ensure system reliability. The inspectors concluded that the operability evaluations were adequate. However, the licensee planned a number of corrective actions to pursue more accurate performance tests.

A revised test Procedure, PBTP-040, " Performance Test of 1HX-15D Containment Fan Cooler," using more accurate service water flow instruments and controlled test conditions, was performed for Unit 1 in March 1996 and a similar test was planned for Unit 2. During this inspection, the inspectors identified that the revised test had not been conducted for Unit 2 and concluded that the results of the Unit 1 test, performed on December 20, 1995, were unreliable.

The inspectors considered this failure to conduct an adequate performance test using a satisfactory test procedure and adequate test instrumentation to be a Violation (VIO 50-266/97026-05(DRP); 50-301/97026-05(DRP)) of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," as described in the attached Notice of Violation.

c. Conclusions

Test control deficiencies associated with the containment accident fan coolers had been identified in 1995, and new tests were to have been performed shortly after the August 1997 restart of Unit 2. However, the new tests had not been performed as of the end of November 1997. One violation was identified.

## IV. Plant Support

### R4 Staff Knowledge and Performance in Radiological Protection and Chemistry

#### R4.1 Corrective Actions Taken to Address Radiation Workers without Self-Reading Dosimeter (SRD)

a. Inspection Scope (IP 71750)

The inspectors reviewed the effectiveness of health physics (HP) department corrective actions taken to address radiation workers entering the radiologically controlled area (RCA) without the required secondary dosimeter (SRD).

b. Observations and Findings

As part of the licensee's problem identification process, CRs were written during 1997 that identified instances where workers entered (or attempted to enter) the RCA without wearing the required SRD. The third quarter trending analysis noted that 32 CRs had been written for the year to date signify[illegible] adverse trend. This prompted licensee management to request a root cause i[illegible]ation of the problem.

Personnel in HP could not determine a single root cause. Worker accountability for maintaining proper radiation worker practices had lapsed and the number of new radiation workers had increased.

The HP department implemented several corrective actions to address the problem. Dosimeter requirements were re-emphasized at a general plant meeting on October 3, 1997, and in a general plant publication. Stronger accountability for proper radiation worker practices was implemented which required that a worker's RCA access be suspended following three noncompliances. An RCA "greeter" was staged at the entrance to the RCA. This individual (usually an HP technician) would verify that the workers were wearing proper dosimeters, question the workers as to the location of and expected time in the work areas, and provide the workers with special information regarding ongoing activities within the RCA.

The inspectors reviewed worker performance following the implementation of these actions. Immediate improvements were noted in worker performance, as reflected in a reduction in CRs referencing this problem. The inspectors observed the performance of the "greeters" at the RCA entrance and concluded that this initiative was effective.

c. Conclusion

The inspectors determined that the HP department was effective in addressing an adverse trend regarding workers failure to wear proper dosimeters.

#### R4.2 Unit 2 Containment Close-out

The health physics manager and the outage planning manager performed a post-outage walkdown of the Unit 2 containment and identified excessive amounts of dirt and debris. This material was removed from containment prior to containment close-out, and the health physics manager stated that permanent corrective actions were going to be implemented to ensure that the containment was thoroughly cleaned following future outages and prior to close-out walkdowns. The inspectors considered the effort to improve containment post-outage cleanliness to be a positive initiative.

## V. Management Meetings

### X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on January 20, 1998. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

## PARTIAL LIST OF PERSONS CONTACTED

Licensee

Wisconsin Electric Power Company (WEPCo)

S. A. Patulski, Site Vice President
A. J. Cayia, Plant Manager
R. G. Mende, Operations Manager
W. B. Fromm, Maintenance Manager
J. G. Schweitzer, Site Engineering Manager
P. B. Tindall, Health Physics Manager
D. F. Johnson, Regulatory Services and Licensing Manager

## INSPECTION PROCEDURES USED

| | |
|---|---|
| IP 37551: | Onsite Engineering |
| IP 40500: | Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems |
| IP 61726: | Surveillance Observations |
| IP 62707: | Maintenance Observations |
| IP 71707: | Plant Operations |
| IP 71750: | Plant Support Activities |

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 50-266/97026-01 (DRP)<br>50-301/97026-01 (DRP) | VIO | Inappropriate Procedure Adherence Guidance |
| 50-266/97026-02 (DRP)<br>50-301/97026-02 (DRP) | VIO | Failure to Enter TS 15.3.0 |
| 50-266/97026-03 (DRP)<br>50-301/97026-03 (DRP) | NCV | "Delta T" Trip Setpoints Not Reduced in Accordance with Technical Specifications |
| 50-266/97026-04 (DRP)<br>50-301/97026-04 (DRP) | NCV | Failure to Perform Inservice Tests Required by ASME Section XI |
| 50-266/97026-05 (DRP)<br>50-301/97026-05 (DRP) | VIO | Failure to Conduct an Adequate Performance Test Using Test Procedure and Test Instrumentation |

Closed

| | | |
|---|---|---|
| 50-266/96011<br>50-301/96011 | LER | "Delta T" Trip Setpoints Not Reduced in Accordance With Technical Specifications |
| 50-266/96006<br>50-301/96006 | LER | Emergency Power Out-of-Service Coincident With Opposite Train Service Water Pump Out-of-Service |
| 50-266/96003<br>50-301/96003 | LER | Plant Operation Outside of Design Basis of the Low Temperature Overpressure Protection System |
| 50-266/96001 | LER | Inadvertent Engineered Safety Features Actuation in Train B Due to DC System Ground |
| 50-266/95011-02(DRP)<br>50-301/95011-02(DRP) | URI | Inadequate Testing of Containment Accident Fan Coolers |

## LIST OF ACRONYMS USED IN POINT BEACH REPORTS

| | |
|---|---|
| AC | Alternating Current |
| AFW | Auxiliary Feedwater |
| ANSI | American National Standards Institute |
| AOP | Abnormal Operating Procedure |
| ASME | American Society of Mechanical Engineers |
| CCW | Component Cooling Water System |
| CFR | Code of Federal Regulations |
| CLB | Current Licensing Basis |
| CR | Condition Report |
| CVCS | Chemical and Volume Control System |
| DC | Direct Current |
| DCS | Duty and Call Superintendent |
| DRP | Division of Reactor Projects |
| ECCS | Emergency Core Cooling System |
| EDG | Emergency Diesel Generator |
| EOP | Emergency Operating Procedure |
| ESF | Engineered Safety Feature |
| EP | Emergency Planning |
| °F | Degrees Fahrenheit |
| FME | Foreign Material Exclusion |
| FSAR | Final Safety Analysis Report |
| HP | Health Physics |
| HVSAT | High Voltage Station Auxiliary Transformer |
| IFI | Inspection Follow-up Item |
| IP | Inspection Procedure |
| IPE | Individual Plant Evaluation |
| IR | Inspection Report |
| ILRT | Integrated Leak Rate Test |
| IT | In-service Test |
| kV | kiloVolt |
| LAN | Local Area Network |
| LCO | Limiting Condition for Operation |
| LER | Licensee Event Report |
| LTOP | Low Temperature Overpressure Protection |
| MSIV | Main Steam Isolation Valve |
| MSS | Manager's Supervisory Staff |
| NCV | Non-Cited Violation |
| NDE | Non-Destructive Examination |
| NRC | Nuclear Regulatory Commission |
| NUTRK | Licensee's Issue Tracking Database |
| OD | Operability Determination |
| OI | Operating Instruction |
| OM | Operations Manual |
| OOS | Out-of-Service |
| OP | Operating Procedure |
| ORT | Operations Refueling Test |
| PAB | Primary Auxiliary Building |

| | |
|---|---|
| PASS | Post-accident Sampling System |
| PBTP | Point Beach Test Procedure |
| PDR | Public Document Room |
| POD | Prompt Operability Determination |
| QA | Quality Assurance |
| RCA | Radiologically Controlled Area |
| RCP | Reactor Coolant Pump |
| RCS | Reactor Coolant System |
| RHR | Residual Heat Removal |
| RMP | Routine Maintenance Procedure |
| RP | Radiation Protection |
| RVLIS | Reactor Vessel Level Indication System |
| RWST | Refueling Water Storage Tank |
| SALP | Systematic Assessment of Licensee Performance |
| SER | Safety Evaluation Report |
| SFP | Spent Fuel Pool |
| SI | Safety Injection |
| SSC | Structures, Systems or Components |
| SW | Service Water |
| TDAFW | Turbine Driven Auxiliary Feedwater |
| TS | Technical Specification |
| URI | Unresolved Item |
| USQ | Unreviewed Safety Question |
| VIO | Violation |
| VNCR | Control Room Ventilation |
| WMTP | Wisconsin Michigan Test Procedure |