U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Wisconsin Electric Power Company
Facility:	Point Beach Nuclear Plant, Units 1 & 2
Location:	6612 Nuclear Road Two Rivers, WI 54241-9516
Dates:	May 26 through July 6, 1998
Inspectors:	P. Louden, Resident Inspector P. Simpson, Resident Inspector M. Kunowski, Project Engineer
Approved by:	J. W. McCormick-Barger, Chief Reactor Projects Branch 7

EXECUTIVE SUMMARY

Point Beach Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-266/98011(DRP); 50-301/98011(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week inspection period by the resident inspectors.

Operations

- Control room operators and supervisors demonstrated a safety-focused and conservative approach to the Unit 1 reactor startup. Briefings for infrequently performed tests or evolutions were good to outstanding, and reactor operator performance during the approach to criticality was good with consistent three-way communications and constant control board monitoring and attentiveness evident. Operators had to contend with unnecessary challenges from secondary system components which distracted their attention and complicated their efforts during the Unit 1 startup. (Section O1.1)

- Unit 1 fuel movements were performed in a careful and deliberate manner and distractions for fuel handling personnel from concurrent activities in the containment were kept to a minimum. (Section O1.2)

- The licensee had not effectively implemented a recently developed defense-in-depth, system maintenance planning matrix. This did not constitute a violation of NRC requirements; however, it represented a deficiency within the production planning group. (Section O3.1)

- The inspectors discussed with station management deficiencies with scheduling an emergency diesel generator post-maintenance test involving the potential inappropriate entry into limiting conditions for operation for the Unit 1 Train "A" residual heat removal system. Upon further review of this issue by station management, the testing was rescheduled to allow for correct plant conditions to be established for performing the test. (Section O3.2)

- A valve mispositioning event was the result of operator error in recalling the specific valve required to be closed. The licensee identified the error and aggressively took actions to evaluate and correct the problem. (Section O4.1)

Maintenance

- Engineering personnel provided good support to the maintenance personnel involved in the troubleshooting, repair, and testing of a Unit 1 "A" main steam line snubber. Maintenance personnel adhered to applicable procedures during the repair work. Appropriate controls existed for foreign material exclusion and use of replacement parts. (Section M1.2)

- The installation of the Unit 1 reactor vessel head was conducted in a safe manner. However, a job supervisor's understanding of the requirements of Nuclear Business Unit Procedure 1.1.4, "Procedure Use and Adherence," regarding procedural adherence was inaccurate. (Section M1.3)

- The licensee identified and effectively corrected a problem regarding the failure to maintain the environmental qualification status of the containment hydrogen monitors for both Units 1 and 2. A Non-Cited Violation was identified involving the failure to provide an adequate procedure to maintain the EQ status of a safety-related component. (Section M3.1)

Engineering

- The licensee identified a calculational error in the service water system hydraulic flow model and subsequently implemented adequate interim administrative operational restrictions as corrective actions. Licensee management committed to submit a Technical Specification change request no later than July 31, 1998, to address the error in the long-term. (Section E2.1)

- The licensee's procedures used during reactor startups and the approach to criticality contained deficiencies which reflected a non-conservative approach to reactivity management since the procedures did not incorporate well-established industry guidance for criticality estimations when using boron dilution to achieve criticality. (Section E3.1)

- A recently completed quality assurance audit of design engineering activities contained additional examples of previously identified concerns with the design engineering organization. The inspectors concluded that, overall, the audit was probing and thorough and appropriately identified design engineering deficiencies. (Section E7.1)

Plant Support

- Radiological postings accurately depicted the radiological conditions in areas inspected. Most areas were maintained free of contamination or kept to a very low contamination level, allowing for access to areas by operators and providing good working environments for the general outage workforce. (Section R1.1)

- Health physics and emergency preparedness staff appropriately responded during a contaminated injured worker drill. The responding medical staff maintained a clear focus on the health and safety of the "victim" that was not overridden by minor radiological control concerns. (Section P1.1)

Report Details

Summary of Plant Status

During this inspection period, Unit 2 operated at approximately 100 percent rated thermal power and Unit 1 completed a scheduled refueling outage which began on February 14, 1998. Unit 1 was made critical on June 27, 1998, at 10:25 p.m. and was placed on line on June 30, 1998, at 12:26 p.m.

I. Operations

O1 Conduct of Operations

O1.1 Unit 1 Reactor Startup

a. Inspection Scope (Inspection Procedures (IPs) 71707 and 71711)

The inspectors observed operations activities for the Unit 1 startup from the Cycle 24 refueling outage. The activities included the approach to criticality and subsequent power ascension. During this inspection, the inspectors reviewed the following documents:

- Operations Manual (OM) 1.1, Revision 2, "Conduct of Plant Operations"
- Reactor Engineering Surveillance Procedure (RESP) 4.1, Revision 13, "Initial Criticality and All Rods Out [ARO] Physics Tests"
- Operations Procedure (OP) 1B, Revision 32, "Reactor Startup"
- OP 1C, Revision 65, "Low Power Operation To Normal Power Operation"

b. Observations and Findings

On June 27, 1998, at 10:25 p.m., the Unit 1 reactor was made critical following the Cycle 24 refueling outage. The inspectors observed operations activities from the approach to criticality through power ascension to 20 percent rated thermal power.

The inspectors observed several briefings for licensee-categorized, infrequently performed tests or evolutions. These briefings ranged in quality from generally good to outstanding. The outstanding briefing, by a senior operations manager, contained a review of procedural notes with an emphasis on precautions and limitations, communication standards, roles and responsibilities of personnel, industry events and contingency actions. In addition, during the approach to criticality briefing conducted by reactor engineering personnel, the operations shift crew displayed an excellent questioning attitude (see Section E3.1).

Reactor operator (RO) performance during the approach to criticality was good as illustrated by consistent three-way communications and constant control board monitoring and attentiveness. Command and control was generally good as reactivity changes and startup activities were directed by a senior reactor operator (SRO) specifically dedicated to Unit 1. Previous inspector-observed command and control weaknesses, documented in Inspection Reports (IRs) 50-266/97016(DRP); 50-301/97016(DRP) and 50-266/97020(DRP); 50-301/97020(DRP), such as a reactor engineer inappropriately directing reactivity changes, were not evident during this reactor startup.

Several times during the Unit 1 startup, operators were challenged or startup activities were delayed by problems with secondary system components. The "A" condensate pump had to be removed from service when its lower motor bearing temperature exceeded pump operating limits. The "A" feedwater pump was tagged-out because of lube oil and casing leaks. The main generator disconnect indicator displayed an intermediate position when the disconnect was actually closed. This later proved to be a position limit switch problem. The "A" motor-driven auxiliary feedwater (AFW) pump developed a leak in its minimum flow recirculation line. This resulted in the "A" motor-driven AFW pump being declared inoperable. The main turbine had to be removed from the turning gear periodically to clean shaft lift pump oil filters because no replacement filters were available. These equipment problems did not meet the operators expectations of what the plant material condition should be for a unit which had just completed a refueling outage.

c. Conclusions

Control room operators and supervisors demonstrated a safety-focused and conservative approach to the Unit 1 reactor startup. Briefings for infrequently performed tests or evolutions were good to outstanding, and reactor operator performance during the approach to criticality was good with consistent three-way communications and constant control board monitoring and attentiveness evident. Operators had to contend with unnecessary challenges from secondary system components which distracted their attention and complicated their efforts during the Unit 1 startup.

O1.2 Conduct of Unit 1 Fuel Reloading Operations (IP 71707)

The inspectors observed Unit 1 fuel reloading activities. The inspectors noted that the fuel movements were well-coordinated among personnel in the Unit 1 containment, at the spent fuel pool, and in the control room. The SROs involved displayed good command and control of the activities. Previously identified inspector concerns regarding distractions during fuel handling operations (IR 50-266/98003(DRP); 50-301/98003(DRP), Section O1.4) did not recur. The fuel movements were performed in a careful and deliberate manner, and distractions for fuel handling personnel from concurrent activities in the containment were kept to a minimum.

O3 Operations Procedures and Documentation

O3.1 Defense-in-Depth Matrix Use Deficiencies

a. Inspection Scope (IP 71707)

The inspectors reviewed the use and operator understanding of a recently developed equipment out-of-service matrix for safeguards, non-Technical Specification (T/S), and non-emergency safety features equipment.

b. Observations and Findings

During a tour of the control room, the inspectors observed a "Defense-in-Depth" matrix status board hanging on the control room wall. The inspectors noted that the matrix contained cross-train maintenance references for safety-related, non-T/S plant equipment. The notes section of the matrix also provided information regarding out-of-service combinations which should be avoided. One of the notes stated that "planned maintenance of the gas turbine shall not be undertaken if any of the emergency diesel generators (EDGs) are out-of-service."

Plant conditions at the time consisted of the gas turbine generator (G05) being out-of-service for maintenance and the Unit 1 Train "A" EDG being out-of-service for an overhaul. The inspectors asked the control room supervisors about the current configuration in reference to the statement on the matrix. Two of the supervisors were not familiar with the matrix, and a third was aware that it had been developed but did not know its purpose. A condition report (CR) (98-2119) was subsequently generated regarding the EDG and gas turbine configuration. Based on a follow-up review of the configuration, the licensee determined that no T/S had been violated and that the specific note referenced was directed at dual-unit operations.

The inspectors discussed this matter with the supervisor of the production planning group (PPG) whose organization was responsible for the implementation of the matrix. The inspectors' concerns focused on the control room supervisors' lack of familiarity with the matrix. If the matrix was not being used, it created a possible distraction in the control room.

The PPG supervisor stated that the new Defense-in-Depth matrix had not been effectively implemented and that operations department personnel had not received training on the new matrix. Corrective actions to be taken in response to CR 98-2119 included training operators and PPG work-week managers on the use of the Defense-in-Depth matrix.

c. Conclusions

The inspectors concluded that the licensee had not effectively implemented a recently developed defense-in-depth, system maintenance planning matrix. This did not constitute a violation of NRC requirements; however, it represented a deficiency within the PPG.

O3.2 Unit 2 Train "A" EDG Test Problems

a. Inspection Scope (IP 71707)

The inspectors reviewed a planned EDG test and evaluated the appropriateness of the licensee entering certain T/S limiting conditions for operation (LCOs) during the test.

Observations and Findings

On June 5, 1998, while reviewing Point Beach Test Procedure (PBTP) 091, "Transient Response of G02 Governor Following Maintenance Activity," Revision 0, a test to be performed a few days later, the inspectors noted that the test required declaring the

Unit 1 Train "A" residual heat removal (RHR) system out-of-service. During a discussion of the test with an RO, the inspectors questioned the planned Unit 1 decay heat removal (DHR) configurations for the test. The RO indicated that he had raised the question about the configuration at an earlier shift briefing but was informed that the condition was allowable by T/S.

Based on the inspectors' understanding regarding the nature of the EDG test, it did not appear that the testing fell under the surveillance aspects of T/S 15.3.1.A.3.b.4, which states that when reactor coolant temperature is less than 140° Fahrenheit (F), one of the two RHR loops may be temporarily out-of-service to meet surveillance requirements. The inspectors discussed this matter with a senior station manager who indicated that he would look into the matter further.

On June 6, 1998, the operations manager and the plant manager informed the inspectors that their reviews of the matter resulted in the determination that the intent of the T/S was to allow for required surveillances as discussed in T/S Section 15.4. The T/S was not appropriate for use when performing post-maintenance testing. As a result, PBTP 091 was re-scheduled and performed at a later time in the outage when the steam generators were available for DHR. This alleviated the concern with the out-of-service configuration of the Unit 1 Train "A" RHR system.

c. Conclusions

The inspectors identified deficiencies with scheduling an EDG post-maintenance test involving the potential inappropriate entry into LCOs for the Unit 1 Train "A" RHR system. Upon further review of this issue by station management, the testing was rescheduled to a point in the outage when plant conditions would be appropriate.

O4 Operator Knowledge and Performance

O4.1 Valve Mispositioning Event During Safety Injection (SI) Check Valve Testing

a. Inspection Scope (IP 71707)

The inspectors reviewed the circumstances and operator responses surrounding a valve mispositioning event which occurred during SI system check valve testing.

b. Observations and Findings

On June 16, 1998, the operations department conducted a routine surveillance test to determine the Unit 1 SI system check valve leak rates as required by T/S 15.4.16. Unit 1 status at the time of the test was: reactor coolant system (RCS) temperature at approximately 160°F, RCS pressure at approximately 340 pounds per square inch gauge (psig), the "A" reactor coolant pump in operation, and the Train "A" RHR system in operation in the normal DHR mode.

The operators in the control room and in the primary auxiliary building were in the process of aligning the Train "B" RHR system for the check valve testing. During the performance of Step 4.8.2 of Technical Specification Test Procedure (TS) 30, "High and Low Head Safety Injection Check Valve Leakage Test," Revision 17, an in-plant operator, after reviewing the required valve position and verifications for the step, entered a contaminated area to perform the tasks. The first valve manipulation required was to shut the 1RH704B RHR "B" pump suction valve; however, the operator began to close the 1RH704A RHR "A" pump suction valve. The operator heard unexpected flow turbulence with the valve about three-quarters of the way shut and reverified with an assisting operator, who was standing outside the contaminated area, which valve was to be closed. The assisting operator stated that 1RH704B was the valve to be shut, and the first operator immediately re-opened the 1RH704A valve.

During this time, the Unit 1 RO received a Train "A" RHR low flow alarm in the control room, noted the decreasing flow, and took action to restore RHR flow and control RCS pressure which had started to increase. Approximately 30 seconds later, RHR flow had been restored and the RO subsequently stabilized the primary system. Operators noted that the Train "A" flow had decreased from 1500 gallons per minute to approximately 220 gallons per minute during the valve closing. The highest RCS pressure observed was approximately 370 psig which was below the low temperature over-pressure protection system set point of 415 psig.

Control room supervision suspended the test while the event was investigated. The momentary reduction in RHR Train "A" system flow brought into question the operability of the "A" RHR pump. An operability determination (OD) was requested to evaluate any possible pump degradation as a result of the event. The OD concluded that the "A" RHR pump remained operable because the lowest flow rate encountered was above the vendor specification for minimum flow for the pump.

Based on interviews and other data evaluated by operations department corrective actions personnel, the root cause of the event was determined to be operator error. The operator had read the step which called for the appropriate valve to be manipulated; however, the operator closed the opposite train valve. The two valves were physically located next to each other. The licensee determined that contributing factors for the event involved the failure to maintain good repeat-back communications when executing procedure steps and the failure to maintain a "continuous use" procedure "in hand" within a contaminated area.

Corrective actions included re-emphasizing self-checking, clear repeat-back communications, and the need for individuals working with a "continuous use" procedure to maintain an "in hand" copy regardless of the location of the work activity.

The inspectors noted that the manipulation of the wrong RHR system valve involved a failure to follow prescribed procedures and was considered a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." However, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV-50-266/98011-01(DRP)).

c. Conclusion

The inspectors concluded that the valve mispositioning was the result of operator error in recalling the specific valve required to be closed. The inspectors determined that the licensee had identified the error and aggressively took actions to evaluate and correct the problem. The resultant violation was considered an NCV.

O6 Operations Organization and Administration

O6.1 Operations Department Organizational Changes

On June 25, 1998, the licensee announced that one of the current assistant operations superintendents would assume a new position in the engineering department. The new assistant operations superintendent was selected from the existing duty shift superintendent (DSS) pool, that is, the pool of second-line supervisory SROs. The vacancy in the DSS pool would be filled by a current duty operations supervisor, a first-line supervisory SRO. These changes were scheduled to be effective in mid-July 1998. The inspectors did not identify any obvious negative impact on the operations department as a result of the changes.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Violation (VIO) 50-266/96007-01(DRP); 50-301/96007-01(DRP): This violation involved three examples of operators failing to follow station procedures. Subsequently, the licensee revised the subject procedures and re-emphasized standards for operator conduct with the operations staff. Over the past year, NRC inspectors have reviewed the implementation of these standards, described in Operations Manual (OM) 1.1, "Conduct of Operations." Based on the results of this review, the inspectors concluded that operator performance, including procedure adherence, has significantly improved (for example, see IRs 50-266/97006(DRP); 50-301/97006(DRP), 50-266/97010(DRS); 50-301/97010(DRS), 50-266/97020(DRP); 50-301/97020(DRP), 50-266/97023(DRS); 50-301/97023(DRS), and 50-266/97026(DRP); 50-301/97026(DRP)).

O8.2 (Closed) VIO 50-266/96007-02(DRP); 50-301/96007-02(DRP): This violation comprised three examples where procedures used by operators resulted in inadequate equipment configuration control. The individual procedures were revised to correct the configuration control errors and, as part of a larger effort to improve the quality of procedures, the licensee reviewed numerous station procedures and equipment lineup checklists to ensure that proper equipment configuration control was maintained. This broader-scope corrective action, which was discussed in Section M8.1 of IR 50-266/98009(DRP); 50-301/98009(DRP), has been effective, overall, in reducing the number of configuration control problems.

O8.3 (Closed) VIO 50-266/96008-01(DRP); 50-301/96008-01(DRP): This violation comprised two examples of inadequate procedures or instructions. In one example, reactor engineering procedures allowed reactor power to reach 3.5 percent with only one reactor coolant pump operating. This conflicted with T/S 15.3.5-2 and 15.3.5-4 for maintaining a minimum number of reactor coolant temperature channels operable during power operations. The procedures were subsequently revised and T/S 15.3.1.A.1.a was also revised to correct a similar conflict.

The second example involved the failure to provide licensee personnel with adequate instructions for performing a weekly qualitative assessment of leakage from a temporary patch on a section of service water (SW) system pipe. After the inspectors notified the licensee of the failure, adequate instructions were provided to personnel. The pipe was subsequently repaired.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Observed Tests and Surveillances (IP 61726)

During this inspection period, the inspectors observed all or portions of the tests and surveillances listed below. The inspectors observed that workers involved with the activities were following the requirements in the appropriate procedures. Operators were attentive to their responsibilities during the activities and system/test engineers were actively involved in the evolutions.

- PBTP 090, "Transient Response Test of G01 Governor Following Maintenance Adjustment," Revision 0
- PBTP 091, "Adjustment and Transient Load Response Test of G02 Governor," Revision 0
- Operations Refueling Test (ORT) 3B, "Safety Injection Actuation with Loss of Engineered Safeguards AC [alternating current](Train B) Unit 1," Revision 29
- ORT 4, "Main Turbine Mechanical Overspeed Trip Device Unit 1," Revision 11

The inspectors also noted that the performance of the control room operators involved with the PBTP 091 test was excellent. The control room operators displayed consistent questioning attitudes, discussed upcoming steps and plant responses among each other, and raised questions to the SRO in charge of the test.

M1.2 Repair of "A" Steam Generator Main Steam Line Snubber 1HS-2

a. Inspection Scope (IP 62707)

The inspectors observed maintenance activities associated with the repair of Unit 1 steam generator "A" main steam header east snubber, 1HS-2.

b. Observations and Findings

During snubber inspections on June 23, 1998, at 11:00 a.m. with the Unit 1 RCS greater than 400°F, the licensee identified that the hydraulic fluid reservoir for the "A" side steam generator snubbers was overflowing. The licensee initiated CR 98-2501 to document the condition. The overflowing reservoir supplied hydraulic fluid to a total of five snubbers, three on the "A" steam generator and two on the "A" main steam line. Engineering personnel evaluated the condition and recommended that all five snubbers be declared inoperable. Operations personnel declared all five snubbers inoperable on June 23, 1998, at 6:00 p.m. Technical Specification 15.3.13.2 requires the snubbers to be restored to an operable status within 72 hours or an orderly shutdown be initiated. The licensee initiated an around-the-clock effort to determine and correct the cause of the problem.

The licensee discovered during troubleshooting that snubber 1HS-2 was low on hydraulic fluid. Maintenance personnel removed 1HS-2 for as-found testing under the control of Work Order 9811536. Performance testing indicated that a problem existed with the internal control unit portion of the snubber. From inspection of the internal control unit by maintenance and engineering personnel, the licensee identified that a check valve had stuck shut. The stuck check valve caused fluid to be ported back to the hydraulic fluid reservoir rather than to the opposite side of the snubber cylinder whenever the snubber piston moved, thus resulting in the overflowing of the reservoir. The licensee did not determine a definitive root cause for the stuck closed check valve because of insufficient conclusive evidence. The snubber was eventually repaired and re-installed and post-maintenance testing results were satisfactory. The snubbers were then declared operable on June 26, 1998, at 4:43 a.m.

The inspectors concluded that engineering personnel's continuous involvement in the evaluation and repair process was an illustration of good support to the maintenance organization. During the troubleshooting and repair phases of the activity, the inspectors noted that maintenance personnel appropriately followed procedures. Additionally, the inspectors noted good foreign material exclusion and material control practices were exercised during the initial disassembly as well as during reassembly of the snubber. The inspectors also observed appropriate implementation of quality control hold points.

c. Conclusions

The inspectors concluded that the testing and the repair work were performed in accordance with approved procedures. Engineering personnel provided good support to the maintenance personnel involved in the troubleshooting, repair, and testing of snubber 1HS-2. Appropriate controls existed for foreign material exclusion and use of replacement parts.

M1.3 Reactor Vessel Head Installation Activities

a. Inspection Scope (IP 61707)

The inspectors observed the installation of the Unit 1 reactor vessel head on May 30, 1998.

b. Observations and Findings

The inspectors attended the pre-job briefing conducted for the installation of the Unit 1 reactor vessel head. Mechanical maintenance personnel performed the work which was directed by Routine Maintenance Procedure (RMP) 9096, "Reactor Vessel Head Removal and Installation," Revision 16. The job supervisor thoroughly discussed the various aspects of the evolution. The job foreman presented the position assignments to each worker ensuring that all personnel involved understood their responsibilities. A health physics (HP) supervisor reviewed radiological controls requirements and answered questions from the workers.

The inspectors determined that the pre-job briefing was conducted well, overall. However, one topic of discussion did reveal some confusion regarding procedural adherence requirements. During the course of the procedure review, the job supervisor stated that if steps had to be performed out-of-sequence, Nuclear Business Unit Procedure (NP) 1.1.4, "Procedure Use and Adherence," allowed a supervisor to alter steps with no further action. Work crew personnel questioned this position given that the procedure was a "continuous use" procedure. The job supervisor maintained that the NP allowed for this discretionary supervisory action. The inspectors discussed this matter with the job supervisor following the briefing.

The inspectors subsequently discussed the procedural adherence interpretation given by the maintenance supervisor with the maintenance manager. The maintenance manager indicated that the supervisor was mistaken and that he would immediately ensure that all maintenance supervisors understood the intent of NP 1.1.4 regarding this matter. Condition Report 98-2244 was written documenting the issue.

The inspectors have previously discussed procedural adherence issues and plant staff misunderstanding of the intent of NP 1.1.4 in IR 50-266/98006(DRP); 50-301/98006(DRP), Section M1.2. A Notice of Violation (NOV) was issued regarding this matter. The inspectors did not identify any procedural adherence violations during vessel head installation; however, the job supervisor's understanding of NP 1.1.4 requirements was inaccurate.

The inspectors had no concerns regarding the actual conduct of the reactor vessel head movement. The evolution was conducted in a careful and safety-focused manner. All individuals involved with the evolution were observed to be following good radiological controls practices, and the crew leader provided clear direction to the work crew.

c. Conclusions

The inspectors concluded that the installation of the Unit 1 reactor vessel head was conducted in a safe manner. However, the job supervisor's understanding of the requirements of NP 1.1.4 regarding procedural adherence was inaccurate.

M3 Maintenance Procedures and Documentation

M3.1 Containment Hydrogen Monitor Environmental Qualification Problems

a. Inspection Scope (IP 37751)

The inspectors reviewed the circumstances surrounding the licensee's identification that the environmental qualification (EQ) requirements for the Unit 1 and Unit 2 containment hydrogen monitors had not been followed.

b. Observations and findings

During a review of the need to replace the existing containment hydrogen monitors, engineering personnel identified that the EQ standards for the hydrogen monitors had not been maintained. The vendor manual for the monitors specified that whenever the connections for the hydrogen sensors were disconnected and reconnected, the terminals were to be coated with an epoxy-type material to provide protection from the environment. Other than records for initial installation, the licensee could not locate any documents or records that indicated the coating had been applied following repair/calibration activities.

Subsequently, all the hydrogen monitors for both Unit 1 and Unit 2 containments were declared out-of-service at 1:16 p.m. on June 15, 1998. A notification was made to the NRC in accordance with 10 CFR Part 50.72(b)(2)(iii)(D) for the inoperable condition of a safety system which prevented it from fulfilling its safety function of mitigating the consequences of an accident. Technical Specification Table 15.3.5-5, Item 10, requires that a minimum of one hydrogen monitor be operable during power operations. Declaring the monitors out-of-service placed Unit 2 in a 72-hour LCO.

The licensee subsequently obtained an equivalent silicone coating material and applied the silicone two days later. The procedure was also revised to include the vendor's requirements for use of the coating. The licensee performed an OD to account for the curing time of the silicone coating because the recommended curing time exceeding the allowed outage time per T/S. The inspectors and technical specialists from the NRC Office of Nuclear Reactor Regulation reviewed the OD and had no concerns.

The root cause of the failure to maintain the EQ of the hydrogen monitors was the absence of a step from the routine maintenance procedure (RMP) 10.34, "Containment Hydrogen Monitors," Revision 11, to apply the terminal coating following repairs. The lack of the terminal epoxy coating invalidated the EQ of the monitors. This non-repetitive, licensee-identified and corrected violation of Criterion V, "Instructions, Procedures, and Drawings," Appendix B, 10 CFR Part 50, is considered an NCV (50-266/98011-02(DRP); 50-301/98011-02(DRP)) consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

The inspectors concluded that the licensee identified and effectively corrected a problem regarding the failure to maintain EQ status of the containment hydrogen monitors for both Units 1 and 2. A Non-Cited Violation was identified involving the failure to provide an adequate procedure to maintain the EQ status of a safety-related component.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) VIO 02073 from Enforcement Action (EA) 96-273: IRs 50-266/96006(DRP); 50-301/96006(DRP) and 50-266/96007(DRP); 50-301/96007(DRP): This issue, pertaining to frequently out-of-calibration pressure gauges on the discharge line of the SI pumps, was discussed in IR 50-266/96006(DRP); 50-301/96006(DRP) and considered with other problems for escalated enforcement. On December 3, 1996, an NOV was issued for those problems (EA 96-273) and included, for the pressure gauges, a violation (VIO 02073) of Criterion XII, "Control of Measuring and Test Equipment," of Appendix B, 10 CFR Part 50. A civil penalty of $325,000 was imposed with the NOV. The licensee committed to extensive corrective actions in its response to the NOV in a letter dated January 31, 1997. For the pressure gauge issue, these actions included the replacement of the local-readout analog gauges with more accurate and reliable remote instrumentation. The licensee eventually installed Foxboro flow transmitters near the pumps and digital flow indicators in the main control room. In addition, the licensee reestablished the tracking and trending of instrumentation and calibration equipment, reemphasized with instrumentation and calibration personnel the use of the condition reporting system for adverse calibration trends and out-of-calibration equipment, and conducted a special review of all installed inservice testing program support instrumentation. Results of reviews by the resident inspectors and by a regional specialist (IR 50-301/98010(DRS)) indicated that the programmatic corrective actions have been effective. During the current inspection, based on a discussion of the new instrumentation with the responsible engineer and the results of a review of calibration records, the inspectors concluded that previous problems with maintaining the SI pump discharge pressure gauges in calibration had been corrected.

M8.2 (Closed) VIO 50-266/96008-02(DRP); 50-301/96008-02(DRP): This violation comprised three examples of failure to follow procedures. In one example, the licensee had recurrent problems with maintenance work request stickers or tags not being removed after maintenance was completed. The licensee revised NP 8.1.1, "Work Order Processing," to clarify requirements and expectations for the use of work request stickers and tags, including the provision of a step in each work order directing workers to remove stickers or tags when maintenance is completed. In addition, training was provided to plant personnel on the proper use and disposition of work request stickers and tags.

The second example involved the failure of plant personnel to write a CR for a washer that had been installed without proper documentation on a casing cover of one of the turbine-driven AFW pumps. Since identification of this problem, the licensee had undertaken a major effort to increase worker participation in the condition reporting process. As discussed in IRs 50-266/97010(DRS); 50-301/97010(DRS) and 50-266/97023(DRS); 50-301/97023(DRS), the inspectors concluded, based on the results of a followup review of the CR system, that this effort has been successful, overall. During the current inspection, the inspectors noted that NP 8.1.1, "Work Order Processing," included a requirement that the originator of a work request initiate the appropriate CR in accordance with NP 5.3.1, "Condition Reporting System," and a requirement that an SRO review the work order to ensure that a CR was initiated, if necessary.

The third example involved several instances of the failure of personnel to follow NP 8.4.10, "Exclusion of Foreign Material from Plant Components and Systems," and maintain proper foreign material exclusion (FME) controls around the spent fuel pool. Since these events, the licensee has revised the procedure to clarify recommendations and requirements and has counseled personnel on the need for proper FME controls. In addition, resident inspector observations of work activities and the results of reviews of condition reports indicated that current FME controls were adequate.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 SW System Hydraulic Analysis Problem

a. Inspection Scope (IP 37751)

The inspectors reviewed a licensee-identified error with the correct assumptions for the isolation of some non-essential SW loads during an accident. This issue was identified as part of an ongoing licensee review of the SW system hydraulic flow analysis model.

b. Observations and Findings

An error was identified in the SW hydraulic flow analysis which had taken credit for isolating the non-essential SW loads during the injection phase of an accident. The licensee identified that five non-essential SW loads would not be isolated. The five loads involved service building, spent fuel pool heat exchanger, Unit 1 turbine building, Unit 2 turbine building, and water treatment sample room. The licensee determined, based on further analysis, that some of the associated valves would close (or would be closed) during the accident sequence; however, none of these valves would isolate all of the non-essential SW loads. During periods when two or more SW pumps were out-of-service, the failure to isolate these non-essential loads would prevent the SW system from maintaining adequate flow and pressure to support safe shutdown. However, if operators were able to isolate the loads for the service building at a minimum, adequate flow and pressure could be maintained for safe shutdown.

In response to the identification of this problem, the licensee performed a 10 CFR 50.59 safety analysis and developed administrative operating limitation instructions for the SW system, which were approved by the Manager's Supervisory Staff (the onsite review committee) on May 29, 1998. These instructions were intended to ensure that the SW system configuration under normal plant conditions satisfied the associated T/S LCOs. In addition, operator actions to isolate the loads were incorporated in applicable emergency operating procedures.

The licensee committed at the exit meeting held on July 9, 1998, to submit a T/S change request to the Office of Nuclear Reactor Regulation, no later than July 31, 1998, to specifically address isolation of non-essential SW loads. The submission of the T/S change will be tracked as Inspection Follow-up Item 50-266/98011-03(DRP); 50-301/98011-03(DRP).

c. Conclusions

The licensee identified a calculational error in the service water system hydraulic flow model and subsequently implemented adequate interim administrative operational restrictions as corrective actions. Licensee management committed to submit a T/S change request no later than July 31, 1998, to address the error in the long-term.

E3 Engineering Procedures and Documentation

E3.1 Reactor Engineering Surveillance Procedure Deficiency During Unit 1 Reactor Startup

a. Inspection Scope (IP 71711)

The inspectors noted a deficiency with the adequacy of RESP 4.1, Revision 13, "Initial Criticality and All Rods Out [ARO] Physics Tests," and OP 1B, Revision 32, "Reactor Startup," during Unit 1 approach to critical.

b. Observations and Findings

Prior to the Unit 1 approach to criticality on June 27, 1998, reactor engineering personnel conducted a pre-evolution brief for control room personnel. At the conclusion of the briefing, the DSS asked the reactor engineer monitoring the startup evolution what the upper and lower limits for the estimated critical boron concentration were and what contingency actions should be taken if those limits were approached; the reactor was to be made critical through dilution of the RCS with all control rods out. The reactor engineer had not predetermined any estimated critical boron concentration limits nor any contingency actions. This resulted in a delay while the reactor engineer and operators determined what limits to use and then calculated the corresponding boron dilution parameters. The limits established were the T/S limits for shutdown margin and maintaining less than a +5°F moderator temperature coefficient. The DSS, in consultation with the reactor engineer, then developed contingency actions to take if the tolerances on estimated critical boron concentration were approached. Unit 1 went critical at 1642 parts per million, very close to the estimated critical boron concentration of 1641 parts per million.

The inspectors determined that neither procedure OP 1B nor RESP 4.1 contained any requirements to determine in advance the tolerances for estimated critical boron concentrations or associated contingency actions should those limits be exceeded. The licensee's procedures for estimated critical control rod position does include control rod position limits. Also, no procedural controls existed for maintaining the RCS boron concentration within T/S limits during the approach to criticality. The reason for diluting to criticality following a core refueling was to approach criticality in a slow, deliberate, and controlled manner while verifying that the new reactor core responds as predicted. Based on a review of industry operating experience, the inspectors noted that establishing limits for both estimated critical rod position and critical boron concentration and the bases for those limits is a common industry practice. In addition, proceduralized contingencies for premature criticality or not achieving criticality within a pre-established band are fundamental industry expectations for reactivity management. Noteworthy, was that the licensee had recently performed a self-assessment (S-A-98-09) of the reactor engineering organization, specifically examining reactivity management, and failed to identify this fundamental deficiency. The inspectors discussed these concerns with plant management.

Upon further review of the procedure deficiencies, the licensee identified that the industry operating experience guidance had been included in previous revisions of RESP 4.1. However, sometime in 1992, during the procedure change process, the guidance was deleted. The inspectors discussed with station management the observation that similar problems of this type had occurred in the past.

c. Conclusions

The inspectors concluded that the licensee's procedures used during reactor startups and the approach to criticality contained deficiencies which reflected a non-conservative approach to reactivity management since well-established industry guidance for criticality estimations were not incorporated into the procedure.

E7 Quality Assurance (QA) in Engineering Activities

E7.1 QA Audit of Design Engineering Processes

The licensee's QA organization conducted a biennial audit of design engineering processes as summarized in Audit Report A-P-98-01, dated June 16, 1998. All major design control activities/products including modifications, temporary modifications, design calculations, engineering specifications, control and review of vendor documents, engineering change requests, and engineering work requests were reviewed to verify compliance with 10 CFR Part 50, Appendix B, Criterion III.

The licensee's audit team concluded that the overall design engineering processes were marginally effective in ensuring the accurate documentation and implementation of design controls. The audit team initiated a total of 22 CRs. In addition, the team could not close two 1997 QA Program Significant Issues related to calculations and translation of design information due to a lack of improvement in those areas.

The inspectors reviewed Audit Report A-P-98-01 in light of recent design engineering performance trends and determined that the audit findings typified previously identified concerns with the design engineering organization. The inspectors concluded that overall, the audit was probing and thorough and appropriately identified design engineering deficiencies.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) VIO 03013 from EA 96-273: IRs 50-266/96006(DRP); 50-301/96006(DRP) and 50-266/96007(DRP); 50-301/96007(DRP): This issue, pertaining to the number of SW pumps needed for accident mitigation, was discussed in IR 50-266/96006(DRP); 50-301/96006(DRP) and in Licensee Event Report 50-266/96004-01; 50-301/96004-01, and considered with other problems for escalated enforcement. On December 3, 1996, an NOV was issued for those problems (EA 96-273) and included, for the SW pump issue, a violation (VIO 03013) of T/S 15.3.3.D and Criterion XVI, "Corrective Action," of Appendix B, 10 CFR Part 50. A civil penalty of $325,000 was imposed with the NOV. The licensee committed to extensive corrective actions in its response to the NOV in a letter dated January 31, 1997. For the SW pump issue, these actions included the prompt preparation and submittal of a license amendment request to correct T/S 15.3.3.D, which did not specify the minimum number of pumps needed for accident mitigation.

On July 9, 1997, Amendments No. 174 (Unit 1) and No. 178 (Unit 2) were issued specifying the minimum number of SW pumps required for design basis accident mitigation. Subsequently, during continuing refinement of its SW model, the licensee identified additional problems with the SW LCO in that the lowest functional capability or performance levels of equipment required for safe operation of the facility was not specified. This issue is discussed further in Section E2.1.

E8.2 (Closed) Inspection Follow-Up Item (IFI) 50-266/96008-05(DRP); 50-301/96008-05(DRP): The inspectors reviewed the issues associated with reverse direction leak testing of gate valves. The licensee identified (in September 1996) that six containment isolation valves (three for each Unit) associated with the containment heating steam system were inappropriately being tested in the reverse direction (the direction opposite to normal flow). The valves were subsequently removed via a modification in which the heating steam supply line containment penetration and the condensate return line penetration were cut and capped. The licensee had not used the containment heating steam system for many years. No other instances of inappropriate leak testing of gate valves were identified. This non-repetitive, licensee-identified and corrected violation of Section III.C.1 of Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," of 10 CFR Part 50, which required that the valves be tested in the direction of normal flow, is considered a NCV (NCV 50-266/98011-04(DRP); 50-301/98011-04(DRP)) consistent with Section VII.B.1 of the NRC Enforcement Policy.

E8.3 (Closed) VIO 50-266/95014-01(DRP); 50-301/95014-01(DRP): This violation involved four examples where safety evaluations for spent fuel dry cask activities were not conducted in accordance with Station Procedure NP 10.3.1, "Authorization of Changes, Tests, and Experiments (10 CFR 50.59 and 72.48 Reviews)." As stated in the cover letter of IR 50-266/95014(DRP); 50-301/95014(DRP), the NRC concluded that the licensee had taken appropriate corrective actions for this violation. These actions included a revision of the procedure to clarify expectations and requirements and better training on the procedure and regulations for personnel who conduct safety evaluations.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 General Comments (IP 71750)

During this inspection period, the inspectors conducted frequent tours of the primary auxiliary building and Unit 1 containment. The inspectors noted that postings accurately depicted the radiological conditions in the areas. Most areas were maintained free of contamination or kept to a very low contamination level, allowing for access to areas by operators and creating good working environments for the general outage workforce. Personnel dose recorded for the Unit 1 outage was 169.7 person-rem (estimated from plant staff records of self-reading dosimeter readings) versus a pre-outage goal of 130.0 person-rem. The main contributors to the higher than anticipated total exposure were 27 person-rem of exposure accrued because of emergent maintenance activities and a total extension of the outage by 61 days.

P1 Conduct of Emergency Planning Activities

P1.1 Contaminated Injured Worker Emergency Response Drill (IP 71750)

The inspectors observed an emergency response drill conducted on June 4, 1998. The drill targeted first responder, control room personnel, site medical, and offsite medical response activities. The inspectors noted that health physics (HP) personnel provided effective radiological controls at the "scene" and the "victim" was assayed for contamination. Control room personnel used the appropriate emergency plan procedure to request an ambulance from an area hospital. Medical workers responding to the "scene" were not impeded unnecessarily by HP personnel. First responder assessment of the "victim's" status was limited. The inspectors could not clearly ascertain if radiological contamination concerns contributed to the first responder's actions. However, upon the medical staffs' arrival at the "scene," a clear focus was maintained on the health and safety of the "victim" and was not overridden by minor radiological control concerns.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management on July 9, 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

S. A. Patulski, Site Vice President
M. E. Reddeman, Plant Manager
R. G. Mende, Operations Manager
W. B. Fromm, Maintenance Manager
C. R. Peterson, Director of Engineering
J. G. Schweitzer, Site Engineering Manager
R. P. Farrell, Health Physics Manager
V. M. Kaminskas, 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 Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 71711:	Startup Following Refueling Outages

ITEMS OPENED, CLOSED, AND DISCUSSED

<u>Opened</u>

50-266/98011-01(DRP)	NCV	Failure to follow procedures, Appendix B, Criterion V
50-266/98011-02(DRP) 50-301/98011-02(DRP)	NCV	Inadequate maintenance procedure, Appendix B, Criterion V
50-266/98011-03(DRP) 50-301/98011-03(DRP)	IFI	Licensee to submit T/S change request to address service water model error
50-266/98011-04(DRP) 50-301/98011-04(DRP)	NCV	Improper leak testing of gate valves, Appendix J

<u>Closed</u>

50-266/98011-01(DRP)	NCV	Failure to follow procedures, Appendix B, Criterion V
50-266/98011-02(DRP) 50-301/98011-02(DRP)	NCV	Inadequate maintenance procedure, Appendix B, Criterion V
50-266/96007-01(DRP) 50-301/96007-01(DRP)	VIO	Operator performance of shift duties
50-266/96007-02(DRP) 50-301/96007-02(DRP)	VIO	Configuration control
50-266/96008-01(DRP) 50-301/96008-01(DRP)	VIO	Leakage/SW leak patch/conditions outside TS
50-266/VIO 02073(DRP) 50-301/VIO 02073(DRP)	EA 96-273	Criterion XII, control of measuring and test equipment
50-266/96008-02(DRP) 50-301/96008-02(DRP)	VIO	Failure to follow procedures

50-266/VIO 03013(DRP) 50-301/VIO 03013(DRP)	EA 96-273	Criterion XVI, corrective action
50-266/98011-04(DRP) 50-301/98011-04(DRP)	NCV	Leak testing of gate valves, Appendix J
50-266/96008-05(DRP) 50-301/96008-05(DRP)	IFI	Containment isolation valve testing discrepancies
50-266/95014-01(DRP) 50-301/95014-01(DRP)	VIO	Inadequate safety evaluation/10 CFR 72.48

LIST OF ACRONYMS USED IN POINT BEACH REPORTS

AC	Alternating Current
AFW	Auxiliary Feedwater
ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CR	Condition Report
DHR	Decay Heat Removal
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
DSS	Duty Shift Superintendent
EA	Enforcement Action
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EP	Emergency Planning
EQ	Environmental Qualification
F	Fahrenheit
FME	Foreign Material Exclusion
FSAR	Final Safety Analysis Report
HP	Health Physics
IFI	Inspection Follow-Up Item
IP	Inspection Procedure
IPE	Individual Plant Evaluation
IR	Inspection Report
ILRT	Integrated Leak Rate Test
IT	In-Service Test Procedure
LCO	Limiting Condition for Operation
LER	Licensee Event Report
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NOV	Notice of Violation
NP	Nuclear Power Business Unit Procedure
NRC	Nuclear Regulatory Commission
OD	Operability Determination
OI	Operating Instruction
OM	Operations Manual
OOS	Out-of-Service
OP	Operations Procedure
ORT	Operations Refueling Test
PASS	Post-Accident Sampling System
PPG	Production Planning Group
psig	Pounds Per Square Inch Gauge
POD	Prompt Operability Determination
PBTP	Point Beach Test Procedure
QA	Quality Assurance
RCS	Reactor Coolant System
RESP	Reactor Engineering Surveillance Procedure
RHR	Residual Heat Removal
RMP	Routine Maintenance Procedure

RO	Reactor Operator
RP	Radiation Protection
RWST	Refueling Water Storage Tank
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SI	Safety Injection
SRO	Senior Reactor Operator
SW	Service Water
TDAFW	Turbine Driven Auxiliary Feedwater
T/S	Technical Specification
TS	Technical Specification Test Procedure
URI	Unresolved Item
VIO	Violation
VNCR	Control Room Ventilation