March 23, 2000

Mr. M. Reddemann
Site Vice President
Point Beach Nuclear Plant
Wisconsin Electric Power Company
6610 Nuclear Road
Two Rivers, WI 54241

SUBJECT: POINT BEACH INSPECTION REPORT 50-266/2000001(DRP); 50-301/2000001(DRP)

Dear Mr. Reddemann:

This refers to the inspection conducted on January 19 through February 28, 2000, at the Point Beach Nuclear facility.

The Point Beach units were operated safely during this period. On January 20, 2000, operators took action to shut down Unit 1 in response to icing in the lake water intake structure. This action was an effective response to the ice build-up, and there were no actual safety consequences associated with the icing condition. However, the icing of the intake structure exposed Operations Department procedural weaknesses and demonstrated that corrective actions implemented following icing events in 1976 and 1978 were no longer effective in their current form. The inspectors also concluded that prior opportunities existed to detect these problems. We will review your corrective actions for this icing event when they are finalized. Also, on February 19, 2000, the senior plant management team made a prudent decision to shut down Unit 1 in response to indications of a loose part in one steam generator.

Based on the results of this inspection, the NRC has determined that four violations of NRC requirements occurred. These violations are being treated as Non-Cited Violations (NCVs), consistent with Section VII.B.1.a of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest these violations or the severity level of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with a copy to the Regional Administrator, Region III, and the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if you choose to provide one, will be placed in the NRC Public Document Room.

Sincerely,

Original signed by
Roger Lanksbury, Chief

Roger Lanksbury, Chief
Reactor Projects Branch 5

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

Enclosure: Inspection Report 50-266/2000001(DRP);
50-301/2000001(DRP)

cc w/encl: R. Grigg, President and Chief
Operating Officer, WEPCo
M. Sellman, Senior Vice President,
Chief Nuclear Officer
R. Mende, Plant Manager
J. O'Neill, Jr., Shaw, Pittman,
Potts & Trowbridge
K. Duveneck, Town Chairman
Town of Two Creeks
B. Burks, P.E., Director
Bureau of Field Operations
J. Mettner, Chairman, Wisconsin
Public Service Commission
S. Jenkins, Electric Division
Wisconsin Public Service Commission
State Liaison Officer

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Sincerely,

/s/Roger Lanksbury, Chief

Roger Lanksbury, Chief
Reactor Projects Branch 5

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

Enclosure: Inspection Report 50-266/2000001(DRP);
50-301/2000001(DRP)

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-266; 50-301
License Nos:	DPR-24; DPR-27
Report No:	50-266/2000001(DRP); 50-301/2000001(DRP)
Licensee:	Wisconsin Electric Power Company
Facility:	Point Beach Nuclear Plant, Units 1 & 2
Location:	6610 Nuclear Road Two Rivers, WI 54241
Dates:	January 19 through February 28, 2000
Inspectors:	F. Brown, Senior Resident Inspector R. Powell, Resident Inspector D. Pelton, Resident Inspector, Braidwood J. Adams, Resident Inspector, Braidwood M. Kunowski, Project Engineer
Approved by:	R. Lanksbury, Chief Reactor Projects Branch 5 Division of Reactor Projects

EXECUTIVE SUMMARY

Point Beach Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-266/2000001(DRP); 50-301/2000001(DRP)

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

Operations

- The inspectors concluded that the January 21, 2000, icing of the intake structure was a repetitive event and a significant condition adverse to quality due to the potential isolation of the safety-related ultimate heat sink source from the plant. Intake structure icing previously occurred in 1976 and 1978. The inspectors further concluded that the SW design basis lower level limit was exceeded due to weaknesses in an Abnormal Operating Procedure (AOP 13A): action levels did not provide margin (time) for operator action; required the use of a non-proceduralized local measurement which introduced systematic errors in the level measurement; and the procedure did not provide guidance to deal with discrepancies between the permanently installed level instrumentation and the local measurement. The operating crew took actions based on pumpbay level data based on these non-conservative errors. Two NCVs were identified: one for the failure to take corrective action to preclude repetition of the 1976 and 1978 events and one for inadequate procedures. The inspectors also determined that the licensee had missed earlier opportunities to identify and correct these problems. (Section O1.1).

- The Unit 1 start-up following the intake structure icing problem and subsequent reactor trip was performed in a safe and controlled manner (Section O1.2).

- The inspectors identified two procedural adherence issues during the Unit 1 start-up that were not entered into the licensee's corrective action program until the inspectors discussed the issue with plant and Operations Department management (Section O1.2).

- The licensee made a prudent decision to shut down Unit 1 in order to investigate the potential that a small loose part was in the hot leg side of the "A" steam generator (Section O1.3).

- The Unit 1 shutdown on February 20, 2000, to investigate a potential loose part in the"A" steam generator hot leg was complicated by material condition problems in the secondary-side systems (Section O1.3).

- The licensee identified a testing discrepancy for the post-accident containment sump valves. The issue was identified appropriately; however, the licensee did not perform a rigorous operability review until questioned by the inspectors. Additional investigation of the valves by the inspectors led to the licensee's identification that internal pressure relief devices in the valves' hydraulic operators had a potential impact on long-term sump valve operability. These internal pressure reliefs had not historically been maintained or tested. The licensee and inspectors independently concluded that reasonable assurance of sump valve operability existed (Section O7.1).

Maintenance

- The inspectors identified a maintenance valve on the hydraulic operator for each of the post-accident containment sump valves that, if mispositioned, could render the long-term mode of core cooling inoperable. The maintenance valves were in the required position but were not locked or sealed in the required (closed) position. The licensee had not been performing the periodic verification of position required by the Technical Specifications for valves that were not locked or sealed. One Non-Cited Violation was identified (Section M1.1).

- The inspectors identified that parts without appropriate quality assurance reviews or documentation had been used when the hydraulic operators for the post-accident containment sump valves were rebuilt. The licensee performed a thorough operability evaluation and concluded that the parts issue had not resulted in the valves being currently inoperable. The inspectors did not identify any problems with the licensee's evaluation. The inspectors concluded that the use of replacement parts without appropriate quality assurance reviews was indicative of a weakness in the licensee's maintenance and materials program. One Non-Cited Violation was identified (Section M1.2).

- The licensee experienced repeated examples of SW leaking through the ceiling of the control room and the adjacent work control center over a period of years. Following a leak identification during this inspection period, the licensee took effective corrective action to preclude reoccurrence. None of the leaks impacted operation or plant safety (Section M2.2).

Engineering

- The inspectors identified an unusual amount of silt in leakage from the safety-related SW system. The licensee provided a reasonable basis for concluding that the safety-related functions of the SW system would not be affected by the observed silt. In reviewing the licensee's evaluation, the inspectors concluded that appropriate progress was not being made in the licensee's efforts to address known weaknesses in the SW system performance monitoring program. The licensee was developing a comprehensive schedule for addressing these weaknesses at the conclusion of the inspection period (Section E1.1).

Plant Support

There were no significant Plant Support area findings during this inspection period.

Report Details

Summary of Plant Status

Both Units entered the inspection period at full power. Operators responded to a reduction in available cooling water (common circulating and service water (SW) source) early on the morning of January 21, 2000. Unit 1 was tripped following a rapid load reduction to approximately 40 percent rated power. Unit 1 was restarted on January 22, 2000, following an investigation of the event. Unit 1 was shut down on February 20, 2000, in response to indications of a loose part in the "A" steam generator. At the end of the inspection period, Unit 1 was in a maintenance outage to investigate indications of a loose part and to perform other corrective maintenance. Unit 2 remained at full power throughout the period.

I. Operations

O1 Conduct of Operations

O1.1 Unit 1 Reactor Shutdown

a. Inspection Scope (Inspection Procedure (IP) 71707)

The inspectors observed and reviewed plant and operator responses to decreasing circulating water inlet forebay water level. The decreasing water level led to the eventual manual tripping of the Unit 1 reactor at 2:39 a.m. on January 21, 2000. The inspectors reviewed the following procedures:

- Operating Instruction (OI) 38, "Circulating Water System Operation," Revision 17;
- OI 70, "Service Water System Operation," Revision 23;
- Abnormal Operating Procedure (AOP) 13A, "Circulating Water System Malfunction," Revision 8;
- Plant Condition Report (CR) 99-2528 dated October 25, 1999; and
- CR 99-2628 dated November 1, 1999.

b. Observations and Findings

On January 20, 2000, the licensee was operating the circulating water system in ice melt mode in accordance with OI 38, "Circulating Water System Operation," Revision 17, due to weather conditions conducive to intake structure icing. The SW system was operating in accordance with OI 70, "Service Water System Operation," Revision 23. At 9:00 p.m., on January 20, 2000, the operating crew entered AOP 13A, "Circulating Water System Malfunction," Revision 8, in response to decreasing forebay water level (common suction source for SW and circulating water). Upon entry into AOP 13A, the operating crew was

required to take local pumpbay measurements. The pumpbay is downstream of the forebay and is separated from the forebay by traveling screens.

At 2:10 a.m., on January 21, 2000, the operating crew entered AOP 17A, Unit 1, "Rapid Load Reduction," Revision 7, as forebay water level continued to decrease. At 2:39 a.m., the Unit 1 reactor was manually tripped by control room operators when the local pumpbay water level measurement reached a level the operators believed to be minus 11 feet (the SW design basis limit). After securing the Unit 1 circulating water pump, the pumpbay water level returned to minus 6 feet by local measurement at 2:53 a.m. The licensee appointed an incident investigation team to determine the root cause of the event and prescribe short-term and long-term corrective actions.

In assessing this event, the inspectors were concerned with the adequacy of, and weaknesses in, procedures used by the licensee during this event and the licensee's corrective actions for prior intake structure icing events.

Procedure Adequacy and Weaknesses

The operating crew performed OI 38, OI 70, and AOP 13A as written, but the SW system was not operated within the existing system model in that forebay level went below the lower limit. The inspectors noted that on January 10, 2000, OI 70 was revised to include reference to the SW design basis forebay lower level limit (minus 11 feet). The OI did not, however, provide specific direction for operator action. The unit shutdown necessary to re-establish design basis forebay level was actually made in accordance with a procedural step in AOP 13A intended to protect the circulating water pumps from damage. The inspectors determined that AOP 13A was inadequate in that it required a local pumpbay level measurement be taken to confirm the control room indication. However, the method for taking the local measurement was neither specified nor controlled by procedure. Additionally, no procedural guidance was provided to operators on how to resolve discrepancies between the two measurements as occurred during this event. Furthermore, the licensee's incident investigation team identified systematic non-conservative errors associated with converting the reading being taken in the pumpbay and the actual pumpbay level. The operating crew took actions based on pumpbay level data that was subject to these errors. The inspectors also noted that plant CR 99-2528 documented that the action levels specified in AOP 13A did not ensure SW design basis functions under analyzed design basis accident scenarios. An Engineering Department review, performed in October 1999, recommended forebay and pumpbay level values of minus 10 feet for Steps 3 and 4 in AOP 13A. However, the AOP had not been revised as of the January 2000 event.

When the Unit 1 reactor was manually tripped, pumpbay level by local indication was minus 11 feet. Incorporating the licensee-identified systematic error in local level measurement and measurement conversion, the pumpbay level was approximately minus 12 feet at the time of trip. However, the pumpbay level continued to decrease until the circulating water pump was secured ten minutes after the unit trip and the actual minimum level was not recorded.

Criterion V, "Instructions, Procedures, and Drawings," of 10 CFR Part 50, Appendix B, required that activities affecting quality be prescribed by instructions appropriate to the

circumstances. Licensee procedure AOP 13A was not appropriate to the circumstances in that it required the use of a non-proceduralized local measurement technique which introduced a systematic error in the level measurement used to validate SW system operability, and the procedure did not provide guidance to deal with discrepancies between the permanently installed level instrumentation and the local measurement. This violation of Criterion V is being treated as a Non-Cited Violation (NCV) (NCV 50-266/2000001-01(DRP); 50-301/2000001-01(DRP)), consistent with Section VII.B.1.a of the NRC Enforcement Policy.

Past Experience With Intake Icing

Intake structure icing previously occurred at Point Beach in 1976 and 1978. As a result of these events, procedural guidance had been established to maintain crib temperatures greater than 34 degrees Fahrenheit during ice melt operations. The licensee's incident investigation team identified that this guidance was modified in late 1982 to establish forebay temperature, not crib temperatures, as the controlling parameter. The team stated that the 1982 change was intended to be interim guidance, in effect only during repairs to the intake structure divider wall. The interim guidance was, however, incorporated into an operating procedure and remained in effect until the January 2000 event. The licensee's root cause evaluation team identified that potential problems with icing of the intake structure had been documented in 1994 (CR 94-047) and 1996 (CR 96-001). Both CRs had been closed without performing a review of the ongoing effectiveness of previous corrective actions. The inspectors were also concerned that an opportunity to identify the 1982 change to the procedural guidance was missed during the licensee's follow-up to the 1999 frozen safety injection line event. The inspectors will continue to evaluate the licensee's actions and effectiveness in preparing the plant for cold weather conditions.

The icing of the intake structure was a repeat event. Criterion XVI, "Corrective Actions," of 10 CFR Part 50, Appendix B, required that measures be established to assure that conditions adverse to quality were promptly identified and corrected. In the case of significant conditions adverse to quality, the measures were required to assure that the cause of the condition was determined and corrective action taken to preclude repetition. The icing of the intake structure was a significant condition adverse to quality in that it had the potential to isolate the safety-related ultimate heat sink source from the plant. The actions taken as a result of the 1976 and 1978 intake structure icing (and as modified in 1982) were inadequate in that they did not preclude repetition. This violation of 10 CFR Part 50, Appendix B, Criterion XVI, is being treated as an NCV (NCV 50-266/2000001-02(DRP); 50-301/2000001-02(DRP)), consistent with Section VII.B.1.a of the NRC Enforcement Policy.

c. Conclusions

The inspectors concluded that the January 21, 2000, icing of the intake structure was a repetitive event and a significant condition adverse to quality due to the potential isolation of the safety-related ultimate heat sink source from the plant. Intake structure icing previously occurred in 1976 and 1978. The inspectors further concluded that the SW design basis lower level limit was exceeded due to weaknesses in an Abnormal

Operating Procedure (AOP 13A): action levels did not provide margin (time) for operator action; required the use of a non-proceduralized local measurement which introduced systematic errors in the level measurement; and the procedure did not provide guidance to deal with discrepancies between the permanently installed level instrumentation and the local measurement. The operating crew took actions based on pumpbay level data subject to these non-conservative errors. Two NCVs were identified: one for the failure to take corrective action to preclude repetition of the 1976 and 1978 events and one for inadequate procedures. The inspectors also determined that the licensee had missed earlier opportunities to identify and correct these problems.

O1.2 Reactor Start-up

c. Inspection Scope (IP 71707)

The inspectors observed control room activities associated with the Unit 1 start-up performed on January 22, 2000. In addition, the inspectors reviewed the following documents:

- Operating Procedure (OP) 1B, “Reactor Startup,” Revision 35;
- OP 1B, Appendix A, “Estimated Critical Position Calculation,” Revision 9;
- AOP 6B, “Stuck Rod or Malfunctioning Position Indication Unit 1," Revision 11; and
- Nuclear Power Business Unit Procedure NP 1.1.4, “Use and Adherence of Procedures and Work Plans,” Revision 5.

b. Observations and Findings

The start-up activities were performed in a safe and controlled manner. Operators were attentive to the appropriate control board indications and generally implemented the start-up procedures as written; however, two minor procedural adherence issues were observed. The inspectors also observed that the operators’ start-up tasks were complicated by the need to respond to a material condition problem. The inspectors were initially told by the Duty Shift Superintendent (the lead senior reactor operator) that the observed minor procedural adherence issues would not be entered into the corrective action program. The CR was initiated after the inspectors discussed the procedure use and adherence issue with the plant and Operations Department management.

The inspectors concluded that the operating crew’s procedure adherence problems were influenced by continuing material condition problems with individual rod position indicators (IRPIs). At 12:25 p.m., during the start-up, the Unit 1 Control Operator withdrew Control Bank “D” control rods in accordance with OP 1B. After the withdrawal, the observed start-up rate remained less than the procedurally required value for a declaration of criticality. The withdrawal resulted in an indication that Rod G-11 was out of alignment from Control Bank “D.” After declaring the reactor critical the crew entered the applicable AOP. Similar problems with IRPIs during start-ups, including required AOP entry, were documented in Inspection Reports (IRs) 50-266/99002(DRP);

50-301/99002(DRP) and 50-266/99008(DRP); 50-301/99008(DRP). The licensee subsequently informed the inspectors that modifications to the IRPIs were planned during the next refueling outage for each unit. These modifications were expected to address the long-standing IRPI indication problems.

c. Conclusions

The Unit 1 start-up was performed in a safe and controlled manner. The inspectors identified two procedural adherence issues during the start-up that were not entered into the licensee's corrective action program until the inspectors discussed the issue with plant and Operations Department management.

O1.3 Unit 1 Reactor Shutdown

a. Inspection Scope (IP 71707)

The inspectors observed portions of the Unit 1 shutdown on February 20, 2000.

b. Observations and Findings

On February 18, 2000, the licensee determined that there was a high probability of a loose part in the hot leg side of the Unit 1 "A" steam generator. This determination was based upon an evaluation of vibrational data obtained from the loose parts monitoring system. The licensee concluded that the potentially loose part was no greater than one half pound, and that an item of this size did not represent a safety concern. Notwithstanding this conclusion, the licensee prudently shutdown Unit 1 to investigate whether a loose part existed and, if so, where it had come from.

The February 20, 2000, shutdown was performed in accordance with OP 3A, "Normal Power Operation to Low Power Operation," Revision 49. Operators performed the shutdown in a professional manner and as prescribed by the procedure. As in the past, material condition problems with the secondary side systems complicated the shutdown. For example, problems with the feedwater regulator bypass valve and the heater drain tank level control system were distractions to the operators.

c. Conclusions

The licensee made a prudent decision to shut down Unit 1 in order to investigate the potential that a small loose part was in the hot leg side of the "A" steam generator.

The Unit 1 shutdown on February 20, 2000, was complicated by material condition problems in the secondary-side systems.

O4 Operator Knowledge and Performance

O4.1 Auxiliary Operator (AO)

a. Inspection Scope (IP 71707)

The inspectors accompanied an AO during the performance of auxiliary building equipment log taking. In addition, the inspectors reviewed the following documents:

- Point Beach Form (PBF) 2031, "Auxiliary Building Shift Log," Revision 42;
- Temporary Change 1999-109;
- 10 CFR 50.59 Screening 1999-1503; and
- CR 00-0302.

The inspectors discussed log taking practices with the AO and with Operations Department management personnel.

b. Observations and Findings

The inspectors determined that, in general, the AO properly logged the operation of auxiliary building equipment in accordance with PBF-2031. The AO demonstrated a good knowledge of equipment and equipment indication locations. The AO also demonstrated sound radiological work practices while taking logs throughout the auxiliary building.

The inspectors noted, however, that the AO had indicated in the logs that component cooling water (CCW) system heat exchanger blowdown was satisfactory. The inspectors noted that the CCW system heat exchanger blowdown block in PBF-2031 referred to Note 25. The inspectors questioned the AO as to the content of Note 25. The AO stated that Note 25 was missing from PBF-2031. The AO stated that operators had submitted a procedure feedback form addressing the missing note the previous week. The AO also stated that he could not recall what was stated in Note 25. Although the AO was unaware of the content of the missing note, the inspectors determined that, based on available indications, CCW system heat exchanger blowdown was satisfactory.

The inspectors also asked the AO if this was an issue that operators would normally document in a CR. The AO stated that he did not know. Documenting the issue in a CR could have brought the issue to the attention of station personnel and prompted timely actions to be taken to correct the problem.

The inspectors discussed this issue with the duty operations supervisor. The duty operations supervisor determined that an error had been made during the copying process which resulted in the copies of PBF-2031 at the AO's station in the auxiliary building not having notes attached to Sheet 15, including Note 25. The affected copies of PBF-2031 were replaced.

c. Conclusions

The inspectors concluded that, in general, the AO properly logged the operation of auxiliary building equipment in accordance with PBF-2031. However, the inspectors concluded that the AO had indicated in the logs that CCW system heat exchanger blowdown was satisfactory without understanding the basis of satisfactory system blowdown. Additionally, the AO did not document the issue on a CR. As a result, the problem had not been identified to station personnel who could have corrected the problem in a timely manner.

O7 Quality Assurance in Operations

O7.1 Failure to Develop a Written Operability Determination (OD) for Post-accident Containment Sump Valve

a. Inspection Scope (IPs 71707 and 37551)

The inspectors reviewed the licensee's response to a documented non-conformance with the Final Safety Analysis Report (FSAR).

b. Observations and Findings

Licensee engineers identified that the post-accident containment sump valves (1,2 SI [safety injection]-850A/B) were not being tested as described in the FSAR. Specifically, Section 6.2.2 of the FSAR stated that the 1,2 SI-850A/B hydraulic operators "are tested" to open the valves against pressures in excess of those experienced during accident conditions. The valves were only being tested against atmospheric pressure. Because of the unique configuration of these valves, the hydraulic operators act directly against the force created by containment pressure on the valves' discs. The post-accident containment pressure would double or triple (depending on the assumptions used) the load on the hydraulic operators for 1,2 SI-850A/B valves. This testing discrepancy was documented in CR 00-0407. The senior reactor operator who reviewed CR 00-0407 for operability implications stated that "Based on testing we currently perform, 1,2 SI-850A/B valves remain operable." Condition Report 00-0407 was reviewed, without comment, by the plant management team on February 4, 2000. Following this management review, the inspectors questioned whether the information documented on the CR provided an adequate basis for concluding that the 1,2 SI-850A/B valves were operable (currently capable of opening under accident conditions). After further review, licensee engineering personnel decided to write an OD.

The OD that was subsequently completed for CR 00-0407 concluded that the 1,2 SI-850A/B valves were operable but nonconforming. The valves were considered to be operable because calculations demonstrated the valve hydraulic operators were designed to open against post-accident containment pressures. However, the OD did not address whether the current maintenance and testing programs provided reasonable assurance that the valves would operate if called under post-accident conditions. Specifically, the OD did not address whether credible degradation mechanisms would be identified by the quarterly valve stroke surveillance tests (the only current test for the

valves). The inspectors reviewed the maintenance histories for the 1,2 SI-850A/B valves, the quarterly valve stroke methodology, and the valves themselves to determine whether any legitimate operability issues existed.

Sections M1.1 and M1.2 of this report describe two issues identified by the inspectors during review of the 1,2 SI-850A/B valves. In addition to these issues, the inspectors identified that the hydraulic pressure indicated at the discharge for the pump of the 1 SI-850A/B valve operators was the same when the valves were opened against 30 pounds per square inch gauge during a one-time test in 1987 as it was with no pressure against the valves during a routine quarterly surveillance test performed on February 11, 2000[1]. The analysis that the licensee had used in developing the OD for CR 00-0407 predicted that the valves would be the same. The inspectors questioned the licensee engineering staff regarding this apparent discrepancy. After some review, the licensee's staff concluded that a pressure relief valve, internal to the hydraulic pump and hydraulic reservoir, was controlling (limiting) the hydraulic pump's output to the valve operator. If misadjusted, or degraded, this pressure relief valve could have created a pump condition where the 1,2 SI-850A/B valves would have opened within the prescribed time during the quarterly valve stroke surveillance test, but would have not opened under accident conditions. Additionally, the pressure relief valves for the four safety injection valves were each set at a different pressure. The inspectors and licensee were unable to identify work orders that addressed the maintenance or as-left settings of the internal pressure relief valves. These issues were documented in CR 00-0515. The inspectors evaluated the wording of Section 6.2.2 of the FSAR, and concluded that the conditions described in CR 00-0407 and CR 00-515 did not represent violations of NRC requirements.

Based upon the independent review of the 1,2 SI-850A/B valves' maintenance history, test methodology, and current visible condition, the inspectors concluded that there was no current operability concern. This finding was consistent with the licensee's conclusion. However, the inspectors' review led to the identification that the licensee's original OD was incorrect (failed to consider the effect of the internal pressure relief valve on operator capacity) and that historical maintenance instructions had been inadequate.

c. Conclusions

The licensee identified a testing discrepancy for the post-accident containment sump valves. The issue was identified appropriately; however, the licensee did not perform a rigorous operability review until questioned by the inspectors. Additional investigation of the valves by the inspectors led to the licensee's identification that internal pressure relief devices in the valves' hydraulic operators had a potential impact on long-term sump valve operability. These internal pressure reliefs had not historically been maintained or tested. The licensee and inspectors independently concluded that reasonable assurance of sump valve operability existed.

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[1]The hydraulic pump discharge pressure was obtained at the request of the inspectors. The surveillance test procedure did not require that this data be recorded, tracked, trended, or analyzed.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Licensee Event Report (LER) 50-266/2000-001-00: Manual Reactor Trip Due to Decreasing Circulating Water Fore Bay Level. This issue was discussed in Section O1.1 of this report.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Missed Surveillance Test (IP 61726)

While reviewing the current material condition of the 1,2 SI-850A/B valves, as described in Section O7.1 of this report, the inspectors observed that valves in the hydraulic supply lines to the valve operators were closed but not locked. The inspectors determined that the valves in question were used to equalize pressure across the sump valve operators during maintenance on the operator. If the maintenance valves open, the sump valve would be inoperable. Technical Specification 15.4.5.II.B.2 required that manual valves whose mispositioning could render an emergency core cooling system inoperable be either locked in position or have its position verified every 31 days. The inspectors knew that operators did not normally enter the tendon galleries (where the maintenance valves are located) during the 31-day surveillance. The inspectors brought this issue to the attention of the duty operations supervisor. The licensee promptly entered T/S 15.4.0.3 for a missed surveillance, verified that the maintenance valve for each of the four sump valves was closed, locked each maintenance valve in the closed position, and exited T/S 15.4.0.3. The failure to lock or verify (every 31 days) the position of the hydraulic line maintenance valves for 1,2 SI-850A/B as required by T/S 15.4.5.II.B.2 is being treated as an NCV (NCV 50-266/2000001-03(DRP); 50-301/2000001-03(DRP)), consistent with Section VII.B.1.a of the NRC Enforcement Policy. The inspectors considered this violation to be similar, but not identical, to the licensee-identified failure to perform T/S 15.4.5.II.B.2 required surveillance tests documented in LER 50-266/99003-00; 50-301/99003-00. This issue is in the licensee's corrective action program as CR 00-0481.

M1.2 Use of Replacement Parts Without Appropriate Quality Assurance Reviews

While reviewing the maintenance history of the 1,2 SI-850A/B valves, as described in Section O7.1 of this report, the inspectors identified an apparent anomaly in the work package for the rebuild of the Unit 1 "B" valve (1SI-850B). Specifically, the work package indicated that the sump valve hydraulic operator had been rebuilt using vendor supplied kits of replacement seals, but there were no Quality Assurance Release tags for these kits. A Quality Assurance Release tag typically served as documentation that parts used during performance of safety-related maintenance activities had received appropriate inspections, and that the parts met the specified quality standards. The inspectors obtained a copy of the computer-based parts list for 1SI-850B and identified that the replacement parts were identified as not requiring quality assurance controls. The inspectors questioned this classification because the seals appeared to have a safety

function that was necessary for operation of the safety-related valve. The licensee was unable to find any documentation that the nonsafety-related parts had been evaluated for use as seals in the safety-related hydraulic operator. The licensee subsequently determined that all four of the 1,2 SI-850A/B valves had been rebuilt using replacement parts that had not received quality assurance inspections and controls. The licensee performed a thorough and prompt OD for the use of the uncontrolled parts, and concluded that the valves were currently capable of performing their safety functions. The inspectors did not identify any concerns with the OD. Criterion VII, "Control of Purchased Material, Equipment, and Services," of 10 CFR Part 50, Appendix B, required that licensees establish measures to ensure that parts used in safety-related applications conform to procurement requirements. The use of replacement parts in an application affecting safety without application of the program measures for ensuring that the parts conformed to the procurement requirements was a violation of 10 CFR Part 50, Appendix B, Criterion VII. This violation is being treated as an NCV (NCV 50-266/2000001-04(DRP); 50-301/2000001-04(DRP)) consistent with Section VII.B.1.a of the NRC Enforcement Policy. This condition was documented in CR 00-0514. The inspectors were concerned by the programmatic aspects of this issue. Specifically, the licensee's procedures for creating work packages allowed the use of non-quality assurance controlled parts in safety-related components without a written or documented basis for the appropriateness of such use. This issue had previously been discussed with the licensee, and was readdressed following the 1SI-850B finding.

M1.3 Emergency Diesel Generator (EDG) G-O2 Maintenance Outage

a. Inspection Scope (IPs 62707 & 71707)

The inspectors observed and reviewed the conduct of maintenance activities and post-maintenance testing associated with the 2-year and 6-year routine maintenance of the G-02 EDG. In addition, the inspectors reviewed the following procedures:

- Routine Maintenance Procedure (RMP) 9043-14, "Emergency Diesel G-01 and G-02 6 and 12 Year Mechanical and Electrical Inspection," Revision 3;
- RMP 9043-21, "Emergency Diesel Generator G-02 2 Year Electrical Inspection," Revision 1;
- RMP 9043-23, "Emergency Diesel Generator G-02 2 Year Mechanical Inspection," Revision 1; and
- RMP 9043-27, "Emergency Diesel Generator G-02 Maintenance Run and Post Maintenance Testing," Revision 3.

b. Observations and Findings

The G-02 EDG was taken out-of-service January 16, 2000, for scheduled 2-year and 6-year routine maintenance. The outage was scheduled to last through January 27, 2000. The diesel was not, however, returned to service until February 2, 2000. The inspectors observed various maintenance and post maintenance testing activities during the outage. Maintenance technicians were knowledgeable of tasks being performed.

In general, the inspectors observed satisfactory use of and adherence to procedures. Plant CR 00-0328 did, however, document one instance where valves were manipulated outside of the scope of Procedure RMP-9043-27. As a result of the valve manipulations, the G-02 engine was inadvertently cranked over while performing subsequent procedure steps to prime the governor booster pump.

The inspectors determined that issues identified during the maintenance activities were properly documented and resolved prior to returning the G-02 EDG to service. Due to the outage extending 6 days beyond the original schedule, the licensee initiated a self-assessment of the G-02 maintenance outage to identify opportunities for improvement prior to the scheduled G-01 EDG outage.

c. Conclusions

The licensee conducted the two-year and six-year routine maintenance of the G-02 EDG during the period of January 16 through February 2, 2000. In general, maintenance and post-maintenance testing activities were properly performed. Due to the outage extending six days beyond the original schedule, the licensee initiated a self-assessment of the G-02 maintenance outage to identify opportunities for improvement prior to the scheduled G-01 EDG outage.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Potential SW Pump Upper Motor Bearing Installation Problem Follow Up

a. Inspection Scope (IP 62707)

The inspectors discussed concerns related to the replacement of the upper motor bearings on the SW pumps with maintenance management. These concerns were originally discussed in IR 50-266/99019(DRP); 50-301/99019(DRP), and Unresolved Item (URI) 50-266/99019-01(DRP); 50-301/99019-01(DRP) was opened to track the issue. The inspectors reviewed upper motor bearing vibration data and analyses for all of the SW pumps.

b. Observations and Findings

During the week of January 3, 2000, the inspectors observed the replacement of the upper motor bearing on SW pump P-32D. The upper motor bearing was being replaced in order to complete Modification MR-97-095. The inspectors identified that the drawing provided in the work package (SK-MR-97-096, page 1 of 4) and bearing installation instructions contained on the same drawing were incorrect. The inspectors informed licensee personnel of the errors and corrective actions were taken to correct the errors and ensure proper installation of the upper motor bearing on SW pump P-32D.

On January 6, 2000, the inspectors met with licensee personnel to discuss the identified problems with Drawing SK-MR-97-095 and the associated installation instructions. The inspectors asked the licensee if the use of this drawing to replace the SW pump upper bearings on the five other SW pump motors could have introduced a mechanism for a

common cause failure into the five SW pumps. The licensee acknowledged the question but did not provide an answer or initiate a CR to enter the concern into their corrective action program. The inspectors opened URI 50-266/99019-01(DRP); 50-301/99019-01(DRP) to track resolution of the inspectors concerns.

On February 2, 2000, the inspectors spoke with the maintenance manager concerning the potential for improperly installed bearings on the SW pumps. The maintenance manager agreed that the potential did exist and discussed corrective actions. To address this concern, the licensee evaluated the effect of improperly oriented bearings and determined that the bearing life would be shortened. Additionally, bearing vibration data and trends were reviewed and no indications of bearing degradation were noted. Service water pump motors with bearing vibration in the alert range were being monitored on an increased frequency. The maintenance manager also indicated that work plan instructions have been revised to include an in-depth inspection of the bearing orientation during the next preventive maintenance inspection. Condition Report 00-0078 was modified to capture the potential for improperly oriented bearings in five of the SW water pumps.

The inspectors reviewed vibration data for all of the SW pump upper motor bearings. The inspectors noted that three SW pumps, P-32A, P-32B, and P-32C, all exhibited an increasing trend. The vibration data on the P-32B and P-32C had exceeded the high alert limit and the data for P-32A was approaching the high alert limit. The inspectors discussed the increasing vibration trends with a component performance monitoring engineer. The inspectors were shown an analysis of the vibration spectrum with respect to vibration frequency and mathematical equations modeling faults in the inner race, outer race, and the balls of the upper motor bearings. The inspectors noted no vibration peaks at the specific frequencies that would indicate failure or degradation of the upper motor bearings.

Based on discussion with the maintenance manager and the component performance monitoring engineer, and the revision of CR 00-0078 to address the potential for improperly oriented bearings, the inspectors determined that the licensee has taken or has planned appropriate actions to address this issue.

c. Conclusions

The inspectors identified that the drawing provided in the work package for the SW pump upper motor bearing replacement was incorrect. This adverse condition was identified only after the upper motor bearings had been replaced on five of six SW pump motors. The inspectors concluded that the licensee had taken appropriate actions to evaluate the effect that improperly installed bearings could have on the SW pump motor performance. The licensee had implemented appropriate performance monitoring techniques to monitor the motor's performance until preventive maintenance inspections could positively verify proper installation of the bearings.

M2.2 Repetitive Problem with SW Leakage through Control Room Ceiling (IP 62707)

Leakage from a rotating strainer in the SW system entered the ceiling of the control room and the work control center on February 20, 2000. The leaking water did not enter any of the control panels, and did not affect any safety-related equipment. This leakage was documented in CR 00-0571. Immediate corrective actions were taken to stop the leakage. Licensee staff informed the inspectors that the strainers would not be placed back in service.

The leaking SW system rotating strainers were located in the ventilation room above, and to the side of, the control room. These strainers had leaked repeatedly over a period of years. None of the leaks had caused known equipment problems. Immediate corrective actions had been taken for each previous leak. The licensee had long-term plans to remove the strainers. The inspectors were concerned that the licensee had accepted periodic leaks in the control room ceiling until the most recent occurrence.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) URI 50-266/99019-01(DRP); 50-301/99019-01(DRP): Failure to address the concern that SW pump motors were modified with an inaccurate sketch referenced in the work plan. This item is discussed in Section M2.1 above.

III. Engineering

E1 Conduct of Engineering

E1.1 Analysis of Silt in the Safety-Related SW System

a. Inspection Scope (IPs 37551 & 71707)

The inspectors monitored the operational status of the SW system on a continual basis. Observed conditions were evaluated for potential impacts on system operability. The inspectors also completed an on-going review of the licensee's program for monitoring the effect of silt and zebra mussels on system and component operability.

b. Observations and Findings

During a walk-down of the SW system conducted on January 25, 2000, the inspectors observed an unusually high amount of silt in the seal (and baseplate) leakage from one of the running SW pumps. The seal leakage from the operating circulating water pumps also appeared to contain more silt than normal. The inspectors were concerned that silt could impact the functionality of safety-related heat exchangers and the auxiliary feedwater pumps. This concern was similar to concerns discussed in Section E2.2 of IR 50-266/99008(DRP); 50-301/99008(DRP) and Section E1.3 of IR 50-266/99013(DRP); 50-301/99013(DRP). The inspectors' latest concerns were documented in CR 00-0267. The licensee's initial operability review for this CR did not address the inspectors' concern that silt could clog heat exchangers and the auxiliary feedwater suction piping.

A subsequent OD provided what appeared to be a complete and thorough basis for reasonable assurance that SW operability was not negatively affected by silt. In reviewing the OD and some of the corrective action program items referenced therein, the inspectors became concerned that appropriate progress was not being made in resolving known weaknesses in the plant's program for monitoring the operation of safety-related heat exchangers. The licensee had committed to implement such a program in response to Generic Letter 89-13, "SW System Problems Affecting Safety-Related Equipment." At the conclusion of the inspection period, the licensee was working on a comprehensive, resource-loaded, schedule for completing the Generic Letter 89-13 monitoring program. The inspectors will continue to track this issue using the existing Inspection Follow-up Item ((IFI) 50-266/99013-03(DRP); 50-301/99013-03(DRP)).

c. Conclusions

The inspectors identified an unusual amount of silt in leakage from the safety-related SW system. The licensee provided a reasonable basis for concluding that the safety-related functions of the SW system would not be affected by the observed silt. In reviewing the licensee's evaluation, the inspectors concluded that appropriate progress was not being made in the licensee's efforts to address known weaknesses in the SW system performance monitoring program. The licensee was developing a comprehensive schedule for addressing these weaknesses at the conclusion of the inspection period.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Routine Radiological Work Practices and Housekeeping (IP 71750)

The inspectors did not identify any significant radiological work practice or housekeeping issues during routine entries into the radiologically controlled area.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management on February 25, 2000. 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

A. J. Cayia, Regulatory Services and Licensing Manager
R. P. Farrell, Radiation Protection Manger
V. M. Kaminskas, Maintenance Manager
R. G. Mende, Plant Manager
B. J. O'Grady, Operations Manger
C. R. Peterson, Director of Engineering
M. E. Reddemann, Site Vice President
D. D. Schoon, System Engineering Manager

NRC

B. A. Wetzel, Point Beach Project Manager, NRR

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities

ITEMS OPENED AND CLOSED

Opened

50-266/2000001-01(DRP) 50-301/2000001-01(DRP)	NCV	Service water design basis limit exceeded due to procedure inadequacy.
50-266/2000001-02(DRP) 50-301/2000001-02(DRP)	NCV	Icing of the intake structure because of failure to maintain corrective actions taken to preclude repetition.
50-266/2000001-03(DRP) 50-301/2000001-03(DRP)	NCV	Failure to lock or verify the position of the hydraulic line maintenance valves associated with the post-accident containment sump valves.
50-266/2000001-04(DRP) 50-301/2000001-04(DRP)	NCV	Use of nonsafety-related parts as seals in a safety-related hydraulic operator without any documented basis.

Closed

50-266/2000001-01(DRP) 50-301/2000001-01(DRP)	NCV	Service water design basis limit exceeded due to procedure inadequacy.
50-266/2000001-02(DRP) 50-301/2000001-02(DRP)	NCV	Icing of the intake structure because of failure to maintain corrective actions taken to preclude repetition.
50-266/2000-001-00	LER	Manual reactor trip due to decreasing circulating water fore bay level.
50-266/2000001-03(DRP) 50-301/2000001-03(DRP)	NCV	Failure to lock or verify the position of the hydraulic line maintenance valves associated with the post-accident containment sump valves.
50-266/2000001-04(DRP) 50-301/2000001-04(DRP)	NCV	Use of nonsafety-related parts as seals in a safety-related hydraulic operator without any documented basis.
50-266/1999019-01(DRP) 50-301/1999019-01(DRP)	URI	Failure to address the concern that service water pump motors were modified with an inaccurate sketch referenced in the work plan.

Discussed

50-266/99013-03(DRP) 50-301/99013-03(DRP)	IFI	Licensee's evaluation of SW system silt on auxiliary feedwater pump operability

LIST OF ACRONYMS USED

AO	Auxiliary Operator
AOP	Abnormal Operating Procedure
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CR	Condition Report
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
FSAR	Final Safety Analysis Report
IFI	Inspection Follow-up Item
IP	Inspection Procedure
IR	Inspection Report
IRPIs	Individual Rod Position Indicators
LER	Licensee Event Report
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
OD	Operability Determination
OI	Operating Instruction
OP	Operating Procedure
PBF	Point Beach Form
RMP	Routine Maintenance Procedure
SI	Safety Injection
SW	Service Water
T/S	Technical Specification
URI	Unresolved Item