U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-266/94002(DRP); 50-301/94002(DRP)

Docket Nos. 50-266; 50-301 License No. DPR-24; DPR-27

Licensee: Wisconsin Electric Company
231 West Michigan
Milwaukee, WI 53201

Facility Name: Point Beach Units 1 and 2

Inspection At: Two Rivers, Wisconsin

Dates: January 19 through February 28, 1994

Inspectors: K. R. Jury
J. Gadzala

Approved By: Mark J. Farber
M. J. Farber, Chief
Reactor Projects Section 3A

3/14/94
Date

Inspection Summary

Inspection from January 19 through February 28, 1994
(Reports No. 50-266/94002(DRP); No. 50-301/94002(DRP))

Areas Inspected: Routine, unannounced inspection by resident inspectors of plant operations, maintenance, engineering, plant support, and corrective actions on previous findings.

Results: One cited violation and one non-cited violation of NRC requirements and two unresolved items were identified. An Executive Summary follows.

Executive Summary

Plant Operations

On February 3, Unit 1 developed a minor reactor coolant leak into the reactor coolant drain tank, shortly after placing the coolant excess letdown system in operation. Reactor power was reduced to slightly below 2% power and the unit taken off line early morning on February 6 to isolate the leak. The source was determined to have been leakage past two manual loop drain isolation valves that were apparently thermally shocked during operation of the excess letdown system, causing them to come off of their seats. (Paragraph 1.c)

Several reactor power quadrant tilt alarms were received during the power ascension following leak repair. Operators were not adequately prepared for the complications that xenon buildup introduced during the power reduction. Inadequate consideration by management of using rods for temperature control during the down power, ineffective communications between management and operators, and ineffective communications between operators and reactor engineers all contributed to the weak response to the flux skewing during the power ascension. Full power was not reached until the evening of February 7. (Paragraph 1.d)

Adequate fire rounds were not performed when a halon fire control system was removed from service. This violation is not being cited because appropriate corrective action was taken. (Paragraph 1.e)

A shutdown of both units was initiated February 8 due to both diesels being inoperable. This resulted in declaration of an Unusual Event. Power had been reduced by about 15% when the shutdown was terminated due to enforcement discretion being granted by the NRC. The units subsequently returned to full power. (Paragraph 2.b)

Maintenance

A loss of indication of safeguards bus voltage occurred unexpectedly, while preparing to perform undervoltage relay replacements, due to the electrical interconnection not appearing on the prints used by engineers preparing the work plans. (Paragraph 2.a)

Several weaknesses were noted during performance of the annual G01 diesel inspection including inadequately labeled oil drums and equipment being staged in the other diesel room. (Paragraph 2.a)

A violation was cited for procedures lacking sufficient acceptance criteria to identify improperly performed maintenance on the G01 diesel generator that led to its subsequent failure. However, prompt and effective response was displayed by plant staff in effecting troubleshooting and repairs on this generator. (Paragraph 2.b)

Engineering

An initial review was performed of the licensee's instrumentation and control system self assessment. No significant concerns were noted. (Paragraph 3.a)

Construction was essentially completed on the new EDG building and work continued on the new diesel fuel oil system. The two new diesels arrived onsite and installation of support systems continued. (Paragraph 3.b).

A reactor coolant sample system containment isolation valve was identified as not being missile protected and the adequacy of a manual isolation valve to serve as a containment boundary was questioned. (Paragraph 3.c)

Plant Support

The licensee conducted severe accident management guideline validations. (Paragraph 4)

DETAILS

1. Plant Operations (71707) (60710) (40500) (93702)

The inspectors evaluated selected activities to confirm that the facility was being operated safely and in conformance with regulatory requirements. These activities were confirmed by direct observation, facility tours, interviews and discussions with licensee personnel and management, verification of safety system status, and review of facility records.

The inspectors observed control room operations, reviewed applicable logs and conducted discussions with Operations staff members. During these discussions and observations, the inspectors ascertained that the staff was knowledgeable of plant conditions, responded promptly and properly to alarms, adhered to procedures and applicable administrative controls, and was aware of inoperable equipment status. The inspectors performed walkdowns of the control boards to verify the operability of selected emergency systems, reviewed tagout records and verified proper return to service of affected components. Shift changes were observed, verifying that system status continuity was maintained and that proper control room staffing existed. Access to the control room was restricted and operations personnel carried out their assigned duties in an effective manner. The inspectors noted professionalism in most facets of control room operation.

In preparation for placing Unit 1 reactor coolant system on excess letdown, which is an infrequently performed procedure, the inspector noted that the Operating Supervisor and the Control Operator performed a detailed joint review of the precautions and limitations of this activity. These actions contributed to the safe and proficient completion of the evolution and contributed to the prompt identification of a coolant system leak which developed during subsequent operation.

Plant tours and perimeter walkdowns were conducted to verify equipment operability, assess the general condition of plant equipment, and to verify that radiological controls, fire protection controls, physical protection controls, and equipment tag out procedures were properly implemented.

During facility tours, inspectors noticed few signs of leakage and that all equipment appears to be in good operating condition. Overall, plant cleanliness has remained good.

a. Unit 1 Operational Status

On February 6, reactor power was reduced below 2% and the unit was taken off line to facilitate isolation of a minor coolant leak. Details appear in paragraph 1.c below. The leak was successfully isolated and the unit placed back online the same morning. Due to problems with quadrant power tilt, full power was not restored until the evening of February 7.

A plant shutdown was initiated February 8 due to both diesels being inoperable. Details appear in paragraph 2.b. Power was reduced to 86% when the shutdown was terminated due to enforcement discretion being granted by the NRC. The unit was returned to full power operation.

The unit operated at full power for the remainder of this period with only requested load following power reductions.

b. Unit 2 Operational Status

A plant shutdown was initiated February 8 due to both diesels being inoperable. Details appear in paragraph 2.b. Power was reduced to 85% when the shutdown was terminated due to enforcement discretion being granted by the NRC. The unit was returned to full power operation.

Unit 2 power was reduced to 52% on February 27 for turbine trip testing and to repair an oil leak on the B main feed pump.

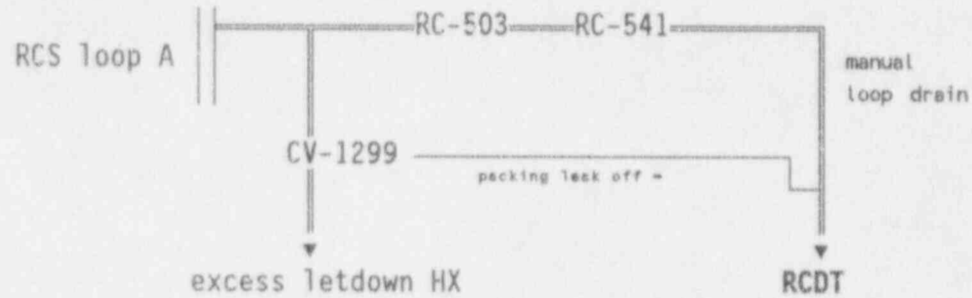
The unit operated at full power during the remainder of this period with only requested load following power reductions.

c. Reactor Coolant System Leak

Unit 1 developed a minor reactor coolant leak February 3 into the reactor coolant drain tank, shortly after placing the coolant excess letdown system in operation.

In preparation for repairing a valve on the normal coolant letdown section of the chemical and volume control system, coolant letdown was shifted from the normal to the excess letdown flow path and the normal letdown path was isolated. At 12:47 p.m., about two hours after excess letdown flow was established, operators noted that reactor coolant leakage had exceeded one gallon per minute. This was identified by a lowering level in the volume control tank and rising level in the reactor coolant drain tank (RCDT). Unit 1 containment air particulate level also rose, but not above any alarm setpoints. Shortly after identifying this leak, operators entered abnormal operating procedure AOP-1A to determine the leak source and attempt isolation. Operators responded well to the event. However, the control room was slow in alerting personnel outside the control room of its occurrence.

Operators entered containment to attempt locating the leak. Drainage piping leading to the RCDT from the A reactor coolant system (RCS) loop was found to be hot. Since the leakage was hot and flowing into the RCDT, this indicated that the leakage source was limited to either seepage past normally shut RCS loop A manual drain valves (RC-503 and RC-541) or a packing leak from the excess letdown heat exchanger inlet isolation valve (CV-1299). A simplified piping diagram appears in figure 1 below. Because motor operated valve CV-1299 was the only one of these valves to have been operated during the lineup for excess letdown, it was suspected as thr leakage source.



[*figure 1.*]

About two hours after initial identification of the leak, repairs on the normal letdown path were completed, normal coolant letdown was restored, and CV-1299 was shut to isolate the excess letdown flow path. However, this did not affect the leak rate, which was determined to be about 2 gpm. Plant management directed that the valve be cycled open and shut, but this still had no affect on leak rate. Further attempts at leak mitigation, including backseating the valve and increasing its closing torque, also had no affect on leak rate. The inspectors closely monitored the licensee's activities.

Technical specifications require that leakage in excess of one gallon per minute be evaluated and a safety assessment made. If the leakage is determined to be unsafe or if it exceeds 10 gpm, the reactor is to be shut down. The Manager's Supervisory Staff determined that they had high confidence that the leakage source was limited to known specific components, it was quantified at 2 gpm, and contained within a system designed to receive it. Containment air particulate activity was steadily trending back down to its normal level, further indicating that the leak was contained. Therefore, the leak was deemed safe; however, the logistics of coping with this leak for an extended period were determined to be unduly burdensome. Therefore, the licensee decided to reduce reactor power sufficiently to attempt leak isolation. This was scheduled for the morning of February 6.

To reduce radiation levels sufficiently to permit access to the area of the coolant loop near these valves, reactor power was reduced to slightly below 2% and the generator was taken off line at 5:14 a.m. Upon entry into the area, personnel discovered that the leakage was not from CV-1299 packing, but seepage past valves RC-503 and RC-541. Apparently, the thermal shock of establishing excess letdown flow was sufficient to cause one or both of these valves to come off of their seats (one valve could have initially been off its seat). Each valve was able to be operated in the shut direction about one-quarter turn, which stopped the leak. All leakage was contained within reactor coolant holding systems.

d. Return to Full Power Operation

After isolation of the Unit 1 coolant leak February 6, the main generator was placed back online at 9:50 a.m. and a power ascension was commenced. Difficulties with xenon buildup resulting from the downpower maneuver interrupted the power ascension and delayed reaching full power until the next day.

At 1:30 p.m. on February 6, with reactor power at 31%, the plant process computer indicated that quadrant power tilt exceeded 2%. Engineering personnel were called to the site and initiated core flux mapping while operators continued the power ascension. Plant procedures did not direct any action in response to quadrant tilt unless a power range channel deviation alarm was received. Operators believed that this alarm was functioning properly but had not reached its actuation setpoint.

At about 6 p.m., reactor power level had reached 60% when the results of the flux map indicated that hot channel factor limits may have been approached. Based on the initial analysis of the flux map, reactor power was reduced to 36%. Additional analysis of the flux map data indicated that it had been skewed by the continuing power ascension. An accurate flux map was then obtained which showed reactor flux parameters within their expected limits. Power ascension was resumed at 8 a.m. on February 7. This power ascension was hampered slightly by delta flux limitations and full power was reached at 6:45 p.m.

Because the unit was late in core life, consideration was given to use of rod insertion for temperature control rather than relying significantly on boron dilution during the downpower maneuver. However, this was not fully evaluated by appropriate levels of management and no formal decision was reached. Operators, however, believed that a decision was reached and as a result utilized rod motion for the down power evolution. Although operators were anticipating a significant xenon buildup, they were not adequately prepared for the complications that it introduced with respect to quadrant power tilt effects. Additionally, procedures used in response to the quadrant power tilt provided equivocal guidance and communications between operators and engineering were initially inadequate to effectively address the condition. As a result, the response to the flux skewing during power ascension was weak.

Plant management initiated an evaluation of this evolution to identify the cause of the weaknesses involved. Appropriateness of the response to the quadrant power tilt and the adequacy of the governing procedures remain unresolved pending completion of this evaluation and subsequent review by the inspector (266/94002-01).

e. Missed Fire Rounds

On February 8, at 7:43 a.m., the auxiliary feedwater (AFW) pump room and the vital switchgear room halon fire suppression system was removed from service for maintenance. As compensatory actions, operators performed twice per shift fire rounds in the AFW pump room and the 4160 VAC safeguards bus room. At 3:15 p.m., the oncoming shift identified that hourly vice twice per shift fire rounds are required by Technical Specification (TS) 15.3.14.4 when the halon system is removed from service. Operators subsequently commenced hourly fire rounds and shortly thereafter, restored the halon system to operation.

The shift supervisor who authorized removal of the halon system had originally recognized that hourly fire rounds were required. However, he inadvertently checked the wrong box on the shift log attachment. The auxiliary operator did not notice this error. The individuals involved were counseled. Plant management's review of this event determined that appropriate procedures were in place to ensure compensatory actions were carried out. Due to the lack of history of a similar occurrence, this was considered an isolated event. The inspector discussed this issue with plant management and had no further concerns. While this is a violation of TS 15.3.14.4, this violation is not being cited because the identification and corrective actions satisfy the criteria specified in Section VII.B of the "General Statement of Policy and Procedure for NRC Enforcement Actions", (Enforcement Policy 10 CFR Part 2, Appendix C).

f. Off Site Review Committee Meeting

The inspector observed limited portions of meeting 51 of the Off Site Review Committee (OSRC). The required quorum was maintained; committee members were experienced in various aspects of the nuclear industry and possessed diverse backgrounds extending outside of NRC Region III. Much of the meeting was held onsite at Point Beach and included tours of the plant and one-on-one interviews with individuals selected by committee members.

Committee discussions observed were candid and constructive and not dominated by the plant staff. The meeting was well documented and action items clearly identified and tracked. Overall, the inspector considered the OSRC to be effective.

2. Maintenance (62703) (61726)

a. Maintenance

The inspectors observed safety related maintenance activities on systems and components to ascertain that these activities were conducted in accordance with technical specifications, approved procedures, and appropriate industry codes and standards. The inspectors determined that these activities did not exceed limiting conditions for operation and that required redundant components were operable. The inspectors verified that required administrative, material, testing, and radiological and fire prevention controls were adhered to.

Selected portions of the following maintenance activities were observed and reviewed:

- SMP 1145 (Revision 0), Replacement of 1-A05 Degraded Grid Voltage Relays

  While performing the equipment isolation in preparation for this activity, voltage indication for 4160 VAC safeguards bus 1-A05 was unexpectedly disabled. Technical specifications require that voltage on this bus be checked each shift for undervoltage and degraded voltage conditions. There was initial confusion among operators regarding the appropriate response and this concern was not adequately communicated to plant management. This condition was eventually resolved by monitoring voltage on bus 1-A03, which is electrically connected to bus 1-A05, along with monitoring 480 VAC safeguards bus 1-B03, which is supplied by bus 1-A05.

  The work procedure did not alert operators to the loss of this bus indication because the engineering prints used to prepare the work plan did not show the interconnection between the meter and the equipment being isolated. Engineers subsequently reviewed more detailed prints and determined that this condition should indeed have been expected. The licensee initiated action to add metering circuit interconnections to the prints.

- RMP 43 (Revision 18), Diesel Annual Inspection

  Several weaknesses were noted during this evolution. The fire door between the two diesel rooms was briefly blocked open to run temporary cables but miscommunication resulted in failure to station a firewatch. Equipment for a G01 fuel modification was initially being staged in G02 diesel room, thereby increasing the potential to inadvertently affect the remaining operable diesel. Lube oil storage drums containing drained oil from G01 to be reused were not adequately labeled. These oil drums were stored in the turbine hall alongside other similar unmarked drums. The inspector brought these concerns to plant management and all deficiencies were corrected.

  While walking down electrical cabling, a contractor inadvertently allowed his wristwatch band to contact across energized positive and negative terminals of a 120 VDC diesel control power breaker. The resultant arc caused burns to the worker's wrist and minor damage to the breaker terminals. The worker was transported to the Two Rivers Community Hospital by coworkers where he was treated and released. The breaker contacts were repaired prior to completion of the diesel outage. No other damage resulted.

b. Failure of Both Emergency Diesel Generators

On February 7, emergency diesel generator (EDG) G02 was removed from service for its TS required annual inspection and preventive maintenance. Standard compensatory measures were implemented, including testing of the 20 MWe G05 gas turbine generator prior to removing the diesel from service and assuring that no work affecting stability of offsite power was performed during the diesel outage. Either of the two EDGs being out of service places the plant in a seven day Limiting Condition for Operation (LCO) per TS 15.3.7.B.1.g and requires daily testing of the operable EDG.

On February 8, while G02 was still out of service, EDG G01 failed. This resulted in both EDGs being out of service simultaneously, a condition prohibited by TS. TS 15.3.0.A requires both units to be placed in hot shutdown within three hours of entry into such a condition. Upon request from the licensee, the NRC exercised their discretion not to enforce compliance with the requirement to shut down both units while the plant completed restoration of G01.

The EDG G01 failure was identified when completing its daily test run on February 8. At about 9 p.m., operators noted small oscillations in the reactive load on the generator. By 9:15 p.m., reactive load was oscillating about 500 kVARs per second while the diesel was loaded to 2700 kW. Operators reduced the diesel's loading and attempted to troubleshoot the problem without success. At 10:04 p.m., G01 was declared inoperable and the engine was shut down. Additional personnel were called in to investigate.

A load reduction was commenced on both units at 10:07 p.m. in preparation for a possible shutdown. An Unusual Event emergency classification was declared as appropriate based on the shutdown required by TS. The NRC was notified of this event as required.

The inspector responded to the site and noted excellent coordination of efforts by engineering and maintenance personnel in the return to service efforts of the G01 diesel. Their efforts were effective in significantly reducing the time needed to restore G01 to an operable status.

The cause of the problem was found to have been an improperly routed electrical cable rubbing against part of the generator rotor. This cable supplies excitation current from the voltage regulator to the generator slip ring assembly and is located in the forward part of the generator, adjacent to the rotor. This cable had been relugged during the most recent G01 maintenance outage that had been performed one week earlier. One of the technicians performing the wiring did not receive an adequate brief on proper routing of the cable, nor did the maintenance procedure contain any guidance or precautions regarding cable routing. Additionally, an excitation field conductor bar, attached to the front of the rotor, was not visible to the technician due to the position that the generator happened to stop at following its last run. When the technician installed the cable, he ensured it would not contact the rotor but was unaware of the unseen conductor bar. When G01 was subsequently operated, the field conductor bar on the rotor would strike this cable as the generator rotated. This eventually wore through the cable insulation and caused a short. The intermittent shorting affected the voltage regulator and resulted in the observed reactive load swings. Replacement parts were obtained from the other diesel to restore G01 to operability.

The improper maintenance is a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." As a result of this violation, both diesels were rendered inoperable at the same time. Multiple work process controls that could have prevented this event, such as proper job turnover and work duration limitations, were not adequately followed (266/94002-02).

Plant management recognized that G01 would not be restored to service prior to expiration of the three hour time limit and requested discretion in enforcement of that limit. A technical specification change request to extend the length of the three hour shutdown limit had previously been submitted and approval was pending NRC review. The NRC subsequently granted enforcement discretion and the load reduction on both units was terminated at 11:19 p.m. with Unit 1 at 86% and Unit 2 at 85% power. The diesel operability test was completed at 2:44 a.m., less than two hours after expiration of the three hour LCO time limit and prior to the 8:00 a.m. extension deadline. Once G01 was restored to service, both units were returned to full power and the Unusual Event classification was terminated. The inspectors closely monitored the plant's restoration activities and had no additional concerns.

c. Surveillance

The inspectors observed certain safety related surveillance activities to ascertain that these activities were accomplished by qualified personnel in accordance with an approved test procedure, test instrumentation was properly calibrated, the tests were completed at the required frequency, and that limiting conditions for operation were met. Upon test completion, the inspectors verified the recorded test data was complete, accurate, and met technical specification requirements; test discrepancies were properly documented, reviewed and resolved by appropriate management personnel; and that the systems were properly returned to service.

Selected portions of the following test activities were observed and reviewed:

- TS-1 (Revision 38), Emergency Diesel Generator G-01 Monthly
- TS-2 (Revision 38), Emergency Diesel Generator G-02 Monthly

No discrepancies were noted during the observance of any of the above tests.

3. Engineering (71707) (40501)

The inspectors evaluated engineering and technical support activities to determine their involvement and support of facility operations. This was accomplished during the course of routine evaluation of facility events and concerns, through direct observation of activities, and discussions with engineering personnel.

a. Licensee Self Assessments Related To Area-Of-Emphasis Inspections (Systems Based Instrumentation and Control Inspection)

The inspectors reviewed the scope and depth of the licensee's instrumentation and control systems self-assessment. This review evaluated the objectivity and independence of the licensee's audit team, including their process for addressing operability concerns (condition reports), prioritization of issues, and corrective actions.

The inspectors concluded the licensee was adequately fulfilling NRC Inspection Procedure 93807, "Systems Based Instrumentation and Control Inspection," objectives. The audit team's inspection plan and checklist followed the inspection requirements described in procedure 93807. The inspectors interviewed audit team members and concluded these members were independently validating plant calculations. Condition reports (CRs) were written as appropriate to address audit team concerns. By procedure, an initial operability screening by a SRO licensed individual was requested within 24 hours and final operability and reportability screening within 3 days of receipt of the CR. The licensee's audit team discussed concerns and unanswered questions with the counterpart team daily and briefed the plant manager once per week.

The inspectors noted that several engineering counterpart team members were located off site at the corporate office. This appeared to weaken communications. Corporate engineering required 6 days to fully understood three concerns involving degraded voltage protection setpoints and time delays and the requirements to address these concerns. The licensee's audit team, with plant management support, requested a face-to-face meeting with the appropriate engineering counterpart team members to discuss these issues. Once direct communications were established, progress was made in addressing the degraded voltage concerns.

The inspectors will continue to follow the licensee's self assessment and document the results in a future report.

b. Construction of New Emergency Diesel Generator Building

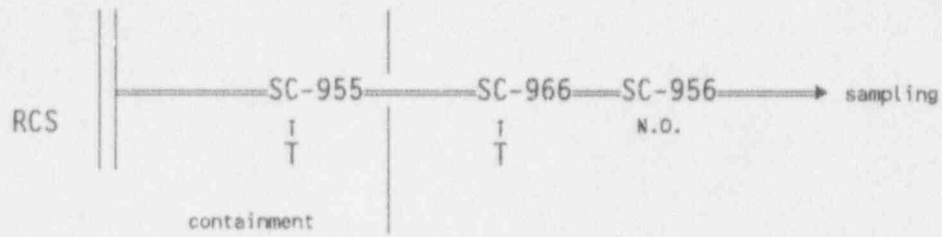
Construction of the building to house two new emergency diesel generators and the new diesel fuel oil system began the week of June 7, 1993. Initial observations of this activity are discussed in Inspection Report 266/301/93011. During this inspection period, building structural work was essentially completed and construction emphasis shifted to interior attachments such as heating, lighting, and installation of diesel support equipment. Fuel lines were laid between the new and existing diesels and tied into the existing diesels' fuel systems. Installation of electrical cabinets and load control centers continued along with cabling pulls. The new G04 and G03 emergency diesels arrived onsite January 12 and 26 respectively and were set in place in their respective bays.

The inspectors monitored various aspects of these activities including the arrival and setting of the new diesels. Discussions were held with craft workers and supervisors to evaluate their knowledge of the job requirements. The inspectors will continue to monitor progress of this construction.

c. Containment Isolation Valve Adequacy

On February 17, plant management determined that one of two containment isolation valves on a coolant sample line was not missile protected and therefore did not satisfy the criteria for a containment isolation valve. This condition, which applied to both units, caused the plant to be outside its design basis and was reported to the NRC as required.

The coolant sample lines contain two trip valves (SC-955 and SC-966), one inside and one outside containment. Additionally, normally open manual isolation valve SC-956 is located downstream of SC-966. Trip valve SC-955 was found to not be missile protected. A simplified diagram appears in figure 2 below.



[*figure 2.*]

The Point Beach FSAR listed valves SC-966 and SC-956 as the containment isolation valves. However, manual valve SC-956 is neither leak tested nor qualified as a containment boundary. Both the trip valves are routinely leak tested. Plant management justified continued operation based on the low probability of a missile event damaging SC-955 coincident with a failure of SC-966. Corrective action was being evaluated with consideration being to provide missile protection for valve SC-955.

An evaluation had already been in progress to reclassify the containment isolation valves in accordance with current design criteria. The evaluation scope included all containment isolation valves listed in the FSAR. The project goal was to designate two trip valves at each containment penetration as the isolation valves and eliminate reliance on manual valves. This project resulted in the identification of the current condition in this system. This issue remains unresolved pending completion of the evaluation and subsequent review by the inspector (266/94002-03).

All activities were conducted in a satisfactory manner during this inspection period.

4. Plant Support (71707)

The inspectors routinely observed the plant's radiological controls and practices during normal plant tours and the inspection of work activities. Inspection in this area includes direct observation of the use of Radiation Work Permits; normal work practices inside contaminated barriers; maintenance of radiological barriers and signs; and health physics activities regarding monitoring, sampling, and surveying. The inspectors also observed portions of the radioactive waste system controls associated with radwaste processing.

From a radiological standpoint the plant is in good condition, allowing access to most sections of the facility. During tours of the facility, the inspectors noted that barriers and signs also were in good condition. When minor discrepancies were identified, the health physics staff quickly responded to correct any problems.

An inspection of emergency preparedness activities was performed to assess the plant's implementation of the site emergency plan and implementing procedures. The inspection included monthly review and tour of emergency facilities and equipment, discussions with company staff, and a review of selected procedures.

The licensee conducted severe accident management guideline validations the week of January 31. These guidelines, drafted by the Westinghouse Owner's Group, provide direction to plant management on responding to accidents beyond those which the plant is designed for. Examples include containment overpressurization, core concrete interaction, and hydrogen combustion. Industry representatives were onsite to observe both table top exercises of the guidelines and simulator scenarios. The observations were used to evaluate the adequacy and usability of the guidelines and initiate revisions as appropriate.

The emergency plan was appropriately implemented as discussed in paragraph 2.b above. Initiation of a required shutdown of both units due to both diesel generators being out of service resulted in the declaration of an unusual event. The inspectors monitored the plant's actions and had no concerns.

The inspectors, by direct observation and interview, verified that portions of the physical security program were being implemented in accordance with the station security plan. This included checks that identification badges were properly displayed, vital areas were locked and alarmed, and personnel and packages entering the protected area were appropriately searched. The inspectors also monitored any compensatory measures that may have been enacted by the plant.

All activities were conducted in a satisfactory manner during this inspection period.

5. Corrective Action on Previous Inspection Findings and Licensee Event Reports (92701) (92702 (92700) (90712)

a. (Closed) Violation (266/93015-01): Failure to Report Initiation of Required Shutdown

A shutdown of both units was initiated on December 3, 1993, due to both diesels being inoperable. The initiation of this shutdown was not reported to the NRC as required by technical specifications. As corrective action, the licensee revised procedure DCS 2.1.1 to clarify the definition of initiation of a reactor shutdown. The inspectors reviewed this revision and had no concerns. During a subsequent event involving initiation of a unit shutdown on February 8, 1994, plant management provided the appropriate notifications to the NRC. This item is closed.

b. (Closed) Inspection Follow Up Item (266/93015-05): Upgrading of the General Considerations Technical Specification (TS 15.3.0)

The time allowance specified in the General Considerations Technical Specification (TS 15.3.0) was identified as a concern during recent events when this specification was invoked. The NRC determined that TS 15.3.0 could be improved to allow a more orderly and safe shutdown of both units than the three hour concurrent shutdown requirement in the current specification. In response to this concern, Wisconsin Electric submitted a proposed change request for Specification 15.3.0 to the NRC on January 26. This item is closed.

c. <u>(Closed) LER 301/93-005:</u> Molded Case Circuit Breakers (MCCB) Fail Trip Tests Due to Grease Solidification

This report describes the potential for a faulted load, supplied by either of two motor control centers (MCC B32 or B42), to cause both these MCC feeder breakers (A train and B train) to open rather than just the faulted load's supply breaker. This would result in loss of power to all safeguards loads powered by these two MCCs.

Based on industry concerns over MCCB reliability and an Electrical Distribution System Functional Inspection issue on MCCB testing, the licensee developed and began implementation of a breaker test and replacement program. A test of ten breakers replaced during the fall 1993 Unit 2 outage revealed that all ten failed the tripping time requirements of Standard NEMA AB4-1991. Five did not trip even when subjected to the instantaneous tripping current for their upstream breakers. The cause was determined to be age related grease solidification in the tripping mechanism. Unit 1 molded case circuit breakers in safeguards buses that supply nonsafety related loads were replaced; a review of the remaining breakers concluded that immediate actions were not required. Replacement of such breakers in Unit 2 was begun the week of January 31, 1994. The licensee recently initiated a circuit breaker testing program whose adequacy will continue to be tracked as an unresolved item (266/93015-06). This report is closed.

<u>Unresolved Items</u>

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, items of noncompliance, or deviations. Unresolved items disclosed during the inspection are discussed in paragraphs 1.d, 3.c and 5.c.

6. <u>Exit Interview (71707)</u>

A verbal summary of preliminary findings was provided to the Wisconsin Electric representatives denoted in Section 1 on March 3, at the conclusion of the inspection. Information highlighted during the meeting is contained in the Executive Summary. No written inspection material was provided to company personnel during the inspection.

The likely informational content of the inspection report with regard to documents or processes reviewed during the inspection was also discussed. Wisconsin Electric management did not identify any documents or processes that were reported on as proprietary.

7. Persons Contacted (71707)

*J. F. Becka, Regulatory Services Manager
J. J. Bevelacqua, Manager - Health Physics
*A. J. Cayia, Production Manager
*F. A. Flentje, Administrative Specialist
W. B. Fromm, Sr. Project Engineer - Plant Engineering
L. D. Halverson, Site Services Manager
F. P. Hennessy, Manager - Chemistry
W. J. Herrman, Sr. Project Engineer - Construction Engineering
N. L. Hoefert, Manager - Production Planning
*T. J. Koehler, Site Engineering Manager
*G. J. Maxfield, Plant Manager
J. A. Palmer, Manager - Maintenance
J. C. Reisenbuechler, Manager - Operations
J. G. Schweitzer, Maintenance Manager
R. D. Seizert, Training Manager
G. R. Sherwood, Manager - Instrument & Controls
T. G. Staskal, Sr. Project Engineer - Performance Engineering

Other company employees were also contacted including members of the technical and engineering staffs, and reactor and auxiliary operators.

*Denotes the personnel attending the management exit interview for summation of preliminary findings.