ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/95-15

License: DPR-46

Licensee: Nebraska Public Power District
1414 15th Street
Columbus, Nebraska

Facility Name: Cooper Nuclear Station

Inspection At: Brownville, Nebraska

Inspection Conducted: October 23 through November 9, 1995

Inspectors: Clifford Clark, Reactor Inspector, Engineering Branch
Division of Reactor Safety

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Division of Reactor Safety
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Approved: for C Paulk
Dr. Dale A. Powers, Chief, Maintenance Branch
Division of Reactor Safety

11-29-95
Date

Inspection Summary

Areas Inspected: Routine, announced inspection of the inservice inspection program and implementation, erosion corrosion program, and followup of a previous maintenance inspection finding.

Results:

Operations

- Not inspected.

Maintenance

- Augmented inspections and revisions were appropriately documented in the inservice inspection program plans (Section 2.1).

- A weakness was identified in which different material thicknesses for the ultrasonic examinations to be performed were not specified in the inservice inspection plan for this outage (Section 2.1).

- Relief requests, changes, and revisions to the inservice inspection program were properly documented. The inservice inspection program for the second 10-year interval had improved considerably (Section 2.1).

- Nondestructive examination procedures were found to be adequate. However, the procedures lacked specific guidance for the examiners (Section 2.2).

- A noncited violation was identified for failure to follow procedure in that a 1-1/2 vee path calibration was used by nondestructive examination technicians instead of a 1/2 vee path calibration as required by procedure (Section 2.3).

- A violation was identified where the licensee did not meet the requirements of the ASME Code regarding centerline marking of replacement welds, and there were no formal or procedural controls established to prevent recurrence (Section 2.3).

- In general, the nondestructive examination observed, were performed in accordance with procedures, except for th deficiencies noted (Section 2.3).

- Overall, the nondestructive examination technicians were observed to be knowledgeable and technically proficient (Section 2.3).

- A violation was identified because the inservice inspection personnel failed to initiate a condition report upon discovery that deficient calibration blocks were used to calibrate ultrasonic instrumentation and perform ultrasonic examinations (Section 2.6).

Engineering

- Isometric drawings were unclear and difficult to understand (Section 2.5).

- Several weaknesses were noted in the implementation of the erosion/corrosion monitoring program activities; however, the licensee was developing an adequate program for long-term erosion/corrosion monitoring in accordance with their commitments to Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning" (Section 3).

- The licensee had not trended erosion/corrosion examination results obtained from previous refueling outages. This indicated a weakness in implementation of a detailed erosion/corrosion monitoring program (Section 3.3.1).

- The contractor nondestructive examination personnel observed were knowledgeable and performed in a competent and professional manner (Section 3 3.5).

- The licensee had not documented a long-term strategy for reducing general erosion/corrosion wear rates, as recommended by industry guidelines (Section 3.3.8.3).

Plant Support

- The results of the independent ultrasonic examinations closely matched, within the expected variations, to those ultrasonic examinations performed by the licensee (Section 2.5).

- Systems were not clearly marked or tagged in the plant, nor on the isometric drawings, for azimuth, elevation, and component identifications (Section 2.5).

- Quality Assurance was conducting inservice inspection audits in accordance with their procedures; however, the licensee recognized that technical expertise was needed to improve the quality and credibility of their audits (Section 2.8).

- There was no Quality Assurance oversight of the licensee's erosion/corrosion monitor program before the 1995 refueling outage (Section 3.3.8.2).

- In general, condition of plant materiel was good and housekeeping was fair, considering an outage in progress (Section 4).

Management Oversight

- The lack of technical review and quality assurance/management oversight of inservice inspection activities resulted inadvertent oversight of ASME Code requirements (Section 2.3).

- The failure to complete program reviews or attain signatures for the 1993 erosion/corrosion examination results by the licensee indicated a weakness in management oversight/implementation of the erosion/corrosion program (Section 3.3.1).

- The licensee had not issued a post-outage erosion/corrosion report for the 1993 refueling outage examinations, which indicated a weakness in management implementation of the erosion/corrosion program (Section 3.3.4).

Summary of Inspection Findings:

- One noncited violation was identified (Section 2.3).
- Violation 298/9515-01 was identified (Section 2.3).
- Violation 298/9515-02 was identified (Section 2.6).
- Violation 298/9318-01 was closed (Section 5.1)

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Documents Reviewed

DETAILS

1 PLANT STATUS

During this inspection period, the plant was in Refueling Outage 16.

2 INSERVICE INSPECTION (73753)

The objectives of this inspection were to ascertain whether the inservice inspection, repair, and replacement of Class 1, 2, and 3 pressure retaining components were performed in accordance with the Technical Specifications, the applicable ASME Boiler and Pressure Vessel Code, correspondence between the Office of Nuclear Reactor Regulation and the licensee concerning relief requests, and requirements imposed by NRC/industry initiatives.

2.1 Inservice Inspection Program and Plans

The inspectors met with the licensee's inservice inspection staff and discussed the second 10-year interval inservice inspection program and scheduled examinations for this outage. The licensee was in the third period of the second 10-year interval. Refueling Outage 16 will be the last refueling outage of the second 10-year interval.

Because of the problems identified in previous NRC inspection reports, the licensee initiated Condition Report 94-1123 to review, evaluate, and revise the inservice inspection program to meet ASME Code requirements and commitments. As a result of this review, additional examinations were required, code boundaries were changed, and the inservice program and plan were revised to incorporate additions and deletions.

The licensee's inservice inspection representative informed the inspectors that the licensee had committed to the requirements of Section XI of the 1980 Edition through Winter 1981 Addenda, ASME Code. The inspectors reviewed the inservice inspection program plan and schedule for the second 10-year interval, third period, Refueling Outage 16. Proposed examinations scheduled for this outage were listed in the inservice inspection program plan by weld identification, code category, system, and type of nondestructive examination to be performed. Augmented inspections and revisions were appropriately documented in the inservice inspection program plan.

The inspectors identified a weakness in which different material thicknesses for the ultrasonic examinations to be performed were not specified in the inservice inspection plan for this outage. The inspectors observed, during inspection of Weld RAW-CF-66, that the inspection plan did not list or address the two different thicknesses of material for the weld examination. This omission of the larger material thickness could have resulted in nondestructive examination technicians performing an examination of both sides of the weld with only the calibration of the smaller material thickness. This could have resulted in inaccurate data.

The inspectors were informed by the licensee and contractor technicians that the examination was only performed on the smaller material thickness side. On at least two instances, the plan failed to identify different base metal thicknesses for the components. Different thicknesses require different calibration standards to perform the examination. In both cases, the technicians had to make more than one entry into the radiation work area to perform the examinations. This weakness led to poor planning for the work tasks, therefore, preventing the technicians from maintaining radiation dose as low as reasonably achievable.

The inspectors reviewed several relief requests submitted to the NRC during the second 10-year interval; however, these relief requests had not been approved by the NRC. The inspectors verified that the Office of Nuclear Reactor Regulations was in the process of reviewing these requests. The inspectors determined that documents describing relief requests, changes, and revisions to the inservice inspection program were properly documented.

The inspectors reviewed several ASME Code cases that had been adopted by the licensee's inservice inspection program. The ASME Code cases that were reviewed by the inspectors were acceptable to the NRC and were listed in Regulatory Guide 1.147.

The inspectors selected inservice inspection records of Class 1, 2 and 3 components examined during previous inspection periods and intervals. These records were reviewed to determine if the licensee had followed their inservice inspection program plan, and were meeting the required ASME Code requirements for components to be examined each inspection period. The records were not easily retrievable in a timely manner by licensee personnel.

Overall, the inspectors concluded that the inservice inspection program for the second 10-year interval had improved considerably. The selection of records reviewed indicated that the licensee had followed their inservice inspection program for previous inspection periods of the second 10-year interval. The licensee had clearly documented changes to the second 10-year interval inservice inspection program.

2.2 Inservice Inspection Procedures and Records Review

The inspectors selected a sample of records from the current inspection period for review. The records were reviewed for completion, technical content, and accuracy. The records were found by the inspectors to be complete and technically accurate.

The inspectors concluded that microfiche historical data was difficult for licensee personnel to retrieve in a timely manner. Historical data was necessary to evaluate and trend indications found during the current inservice inspection.

The inspectors reviewed the licensee's nondestructive examination procedures for compliance to the ASME Code and other commitments the licensee had made to the NRC. The nondestructive examination procedures were found to be adequate. However, the procedures lacked specific guidance in that some important inspection variables were left to the skill and discretion of the examiner. No deficiencies were noted because of the lack of specific guidance.

Procedures reviewed by the inspectors are listed below:

PROCEDURE TITLE	PROCEDURE NUMBER	REVISION/DATE
Manual UT of Ferritic Piping Welds	UT-CNS-106V0	0/ 10/10/95
Manual UT of Similar & Dissimilar Metal Piping Welds	UT-CNS-102V0	0/ 10/10/95
Linearity Checks on UT Instruments	ADM-CNS-1001V0	0/ 10/10/95
Manual UT Planar Flaw Sizing	UT-CNS-104V0	0/ 10/10/95
Data Review and Analysis of Recorded UT Indications	ADM-CNS-1002V0	0/ 10/10/95
Automated UT of the Shroud Assembly Welds	UT-CNS-503V4	0/ 10/10/95
Cooper Shroud OD Accessibility Study	ADM-CNS-1022V0	0/ 10/10/95

2.3 Observation of Nondestructive Examinations

Nondestructive examination activities observed by the inspectors included ultrasonic and magnetic particle examinations.

The inspectors observed nondestructive examination technicians perform a magnetic particle examination (HPEX-CF3) on a 50.8 cm [20 in] main steam line inside Room R-859-HPCI. The nondestructive examination technicians verified the following: magnetic yoke lifting power was adequate; surface area was clean and free of dirt; magnetic field of direction was sufficient before performing the examination; and, at least two separate examinations were performed on each area. The inspectors concluded that the magnetic particle examination was being performed in accordance Procedure MT-CNS-100V1, "Magnetic Particle Examination (Dry Particle Color Contrast or Wet Particle Fluorescent)," Revision 0, and the ASME Code, Section V.

The inspectors also observed several ultrasonic examinations performed during this inspection. The inspectors observed nondestructive examination technicians perform the calibration and examination, record the indications, and utilize the correct nondestructive examination procedure on various welds and systems. In some instances, the calibration selected by the nondestructive examination technicians was not in accordance with the required procedure. During observation of the ultrasonic examination of Weld RHB-CF-20, the nondestructive examination technicians were observed using a 1-1/2 vee path calibration. Procedure UT-CNS-106V0, "Manual UT Exam of Ferritic Piping Welds," Revision 0, specified that 1/2 vee path calibrations were desirable to obtain the best resolution possible; therefore, when the basic calibration blocks allow, side or end drilled holes for distance amplitude curve construction should be used. Contrary to the above, the nondestructive examination technicians used a 1-1/2 vee path calibration. The inspectors determined that a 1/2 vee path calibration could have been performed on this weld, because both sides of the weld were accessible. Technically, the inspectors concluded that no safety concerns existed; however, this was a failure of the nondestructive examination technicians to follow procedure. This failure to follow procedure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.

The inspectors attempted to witness the automatic ultrasonic examination of the core shroud welds which was scheduled to be performed during the back-shift hours. However, the nondestructive examination contractor experienced tooling and set-up difficulties. As a result of these examination delays by the contractor, the inspectors were unable to witness the examination of the core shroud welds.

While observing nondestructive examinations, the inspectors did not notice any identification markings on the welds, nor any kind of reference system to locate the welds. The 1980 ASME Code, Winter 1981 Addenda, Section XI, Mandatory Appendix III, Article III-4000, Paragraph III-4330, states, in part, that "[c]ircumferential welds in Class 1 and 2 piping requiring volumetric examination shall be marked [in reference to weld centerline] once before or during preoperational examination to establish a reference point." Since pre-service examination was not performed at Cooper Nuclear Station, existing welds were excluded from this requirement. Several examinations performed at Cooper Nuclear Station during this period were being considered pre-service examination, such as Weld No. RHB-CF-60, as stated on the examination summary sheets for the piping weld examinations. However, all piping replacements must adhere to the requirements of ASME Code, Section XI.

The inspectors questioned the licensee inservice inspection staff and the contractor if they had established a reference system including permanently marking the welds, for determining the actual centerline of the weld. The inspectors were informed by a contractor inservice inspection representative that they did not permanently mark the welds. However, the licensee's inservice inspection representative informed the inspectors that he thought that marking of the welds may have be done on recent examinations conducted. Further investigation by the inservice inspection representative indicated that before 1991, there was no indication that any reference system was established or that replacement welds were permanently marked. However, the inservice inspection representative found Maintenance Work Requests MWR 91-3330 and 93-1381 that did specify in the instructions to mark the welds. No licensee inservice inspection staff knew how or why the two maintenance work requests instructions included the requirement to mark the welds during the discussions with the inspectors. When questioned by the inspectors on how the licensee would assure themselves that all replacement welds would be permanently marked as required by the ASME Code, the inservice inspection representative could not give the inspectors an answer.

The licensee inservice inspection staff initiated Condition Report No. 95-1192 to address this deficiency. The inspectors determined that the lack of technical review and quality assurance/management oversight of inservice inspection activities resulted in this inadvertent oversight of ASME Code requirements.

Technically, the inspectors determined that no immediate safety concerns existed for these welds; however, the licensee did not meet the requirements of the ASME Code regarding centerline marking of replacement welds, and there were no formal or procedural controls established to prevent recurrence. Additionally, the inspectors identified this deficiency. This failure to establish a reference system for determining the actual centerline of the weld, including permanently marking the welds, is a violation of ASME Code requirements (298/9515-01).

The inspectors concluded that, in general, the nondestructive examinations observed were performed in accordance with procedures, except for the deficiencies noted. Overall, the nondestructive technicians were observed to be knowledgeable and technically proficient.

2.4 Personnel Qualifications and Certifications

The inspectors reviewed documentation for certification of nondestructive examination personnel. All nondestructive examinations performed at Cooper Nuclear Station for inservice inspection were provided by a contractor. All contractor Level II and Level III nondestructive examination certifications at the site were reviewed by the inspectors. All certifications and annual eye examinations were current. No concerns were identified for those certifications reviewed.

2.5 Independent Ultrasonic Examinations

The inspectors performed independent ultrasonic examinations on various ASME Code Class 2 piping welds in the core spray, residual heat removal, and reactor water clean-up systems. To obtain the greatest possible repeatability in performing the independent measurements, the examinations were performed utilizing transducers, cables and ultrasonic instruments that closely matched those used by the licensee's contract nondestructive examination technicians. The distance amplitude correction curves were established utilizing the licensee's inservice inspection calibration standards.

The inspectors examined six welds: RHB-CF-20, RAW-CF-66, RAW-CF-1, RHB-CF-60, RWCU-97, and RWCU-26. During this independent inspection, the inspectors had difficulty performing system walkdowns using the isometric drawings provided by the licensee. Systems were not clearly marked or tagged in the plant, or on the isometric drawings, for azimuth, elevation, and component identifications. The inspectors determined that the obscure drawings could lead to incorrect weld identification, as well as increasing unnecessary radiation exposure. The inspectors noted that these unclear and difficult to understand isometric drawings were a weakness in the inservice inspection program implementation process.

The results of the inspectors' independent ultrasonic examinations closely matched, within the expected variations, those performed by the contract nondestructive examination technicians.

2.6 Review of the Effectiveness of Licensee Controls

During this inspection, the inspectors reviewed the licensee's inservice inspection program to determine if effective controls had been established to identify, resolve, and prevent problems. The inspectors noted that calibration blocks from the Duane Arnold Nuclear Plant were shipped to Cooper Nuclear Station for use in performing inservice inspection program examinations. Licensee work instructions specified that the calibration blocks received from the Duane Arnold Nuclear Plant be inspected and verified acceptable prior to release for use in performing inservice inspection examinations in this plant.

The inspectors were informed that there was a period of time after receipt of the Duane Arnold Nuclear Plant calibration blocks during which the licensee's inservice inspection staff had temporarily lost control of them. This was prior to the engineering department's inspection acceptance and release of the blocks. During the period of time that control was lost, the calibration blocks were used by contractor technicians to calibrate and perform ultrasonic examinations. Discussions with the inservice inspection coordinator indicated that later, upon review of the calibration blocks dimensional specifications, it was identified that the depth of the notches were not within the acceptable tolerances. The inspectors were informed by the inservice inspection coordinator that the contractor technicians had been told verbally not to use the Duane Arnold Nuclear Plant calibration blocks until the licensee's engineering group had verified the calibration blocks were within acceptable tolerances and released them for use.

In reviewing this issue, the inspectors found that the licensee had controls in place, such as work packages, overview of work by the inservice inspection staff, and review of data, to prevent this problem; however, these controls failed. Additionally, even though these deficient calibration blocks were identified by licensee engineering, a condition report was not prepared to document and control the correction of this deficiency.

In and of itself, the fact that no condition report was prepared by the inservice inspection personnel to identify the issue and track the root cause analysis and corrective actions initiated to prevent recurrence is not a significant issue. However, this reluctance to initiate condition reports has been a continuing concern to the NRC. It was not until the inspectors discussed this specific issue with licensee inservice inspection personnel that a condition report was prepared.

Administrative Procedure 0.5, "Condition Reporting," Revision 3, stated that any individual aware of an undesirable or questionable condition is responsible for initiating a condition report. Contrary to the above, no condition report was written until questioned by the inspectors. This failure to initiate a condition report was a violation of procedure (298/9515-02).

2.7 Code Repair and Replacement Activities

The inspectors observed portions of code repair and replacement work activities performed on Valve SW-V-78, the discharge valve to the A residual heat removal service water booster pump. This valve was an ASME Class 3 component. The inspectors observed the welder perform the remaining weld passes to complete the valve body installation. A current hot work permit and fire watch were posted in the area. The work package reviewed by the inspectors contained appropriate information to perform the work. The welder was performing the work in accordance with the work instructions.

2.8 Quality Assurance Audits

The inspectors reviewed Audit Report No. 93-10, an audit conducted by the licensee quality assurance department in the area of inservice inspection. The audit report did not identify any findings. Discussions with the quality assurance supervisor indicated that audits were conducted during refueling outages, and that inservice inspection Audit 95-23 was in progress during this inspection. The inspectors were shown the detailed report and audit checklist for Audit 95-23, which appeared to be more comprehensive than the previous Audit Report 93-10. The quality assurance supervisor acknowledged that additional technical expertise was needed in quality assurance to perform these inservice inspection audits.

The inspectors concluded that the licensee was conducting inservice inspection audits in accordance with their procedures; however, the licensee recognized that technical expertise was needed to improve the quality and credibility of the inservice inspection audits. The inspectors were informed by the quality assurance supervisor that their plans were to hire an individual with inservice inspection experienced.

3 INSPECTION OF THE EROSION/CORROSION MONITORING PROGRAM AND ITS IMPLEMENTATION (49001)

3.1 Introduction

The purpose of this inspection was to evaluate the licensee's long-term erosion/corrosion monitoring program to determine: if the program was being conducted in accordance with NRC guidelines established in Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning"; if the program was being conducted in accordance with licensee commitments and procedures; how well management controlled problems; whether generic weaknesses exist related to implementation of the long-term erosion/corrosion monitoring program; and, if quality assurance or independent reviews of the program had been conducted.

3.2 Program Description

The licensee noted that, in 1983, they began inspecting for erosion/corrosion damage with the implementation of Special Test Procedure 83-6, "Balance of Plant Erosion Monitoring," dated March 11, 1983. The initial development of the licensee's formal erosion/corrosion inspection program was documented in Cygna Energy Services Document TR-87165.02, "Cooper Nuclear Station Erosion/Corrosion Inspection Program Final Report," Revision 0, dated December 1987. Later, in April 1992, ABB Impell Corporation performed a comprehensive review of the licensee's erosion/corrosion inspection program, which was documented in an attachment to ABB Impell Letter 0084-00188-002. The attachment to ABB Impell Letter 0084-00188-002 was entitled "Erosion-Corrosion Program Evaluation Cooper Nuclear Station," Revision 0, dated May 1992. This ABB Impell evaluation also provided 23 recommendations for program improvement. Before 1993, selection of erosion/corrosion inspection locations was based on the initial program selection criteria identified in Document TR-87165.02 and industry experience.

In January 1993, the licensee used the CHUG/CHECMATE family of computer codes developed by the Electric Power Research Institute to analytically predict the piping system locations most susceptible to pipe wall thinning. The licensee selected the erosion/corrosion inspection locations for the 1993 refueling outage in accordance with the Cygna Report, data from previous inspections, industry experience, and the CHECMATE results.

The licensee had reinspected areas identified by their analysis as being susceptible to flow-accelerated corrosion to obtain actual wear rates. According to engineering personnel, before the 1995 refueling outage, flow-accelerated corrosion wear measurements were obtained from five previous outages in 1988, 1989, 1990, 1991, and 1993. From the review of the data obtained from these previous outage examinations, the licensee engineers had established actual wear rates for inspection and replacement projections.

The current erosion/corrosion program covered various forms of erosion/corrosion including, but not limited to, the following: flow-accelerated corrosion, previously known as erosion/corrosion; hard particle erosion; liquid impingement erosion; cavitation wear; and microbiologically-induced corrosion.

The licensee engineering personnel identified that their current erosion/corrosion program was documented and implemented using the following procedures:

- "Flow-Accelerated Corrosion Susceptibility Screen of Piping Systems at CNS," Revision 0, dated August 1995;
- "Microbiologically Induced Corrosion (MIC) UT Monitoring Program," Revision 0, dated September 1994;
- 3.10, "Examination and Evaluation of Pipe Wall Thinning," Revision 4.3, effective date of October 15, 1995;
- Cooper Nuclear Station CHECMATE Model, ABB Impell Corporation, Calculations 0084-00193-001 through 007.

The inspectors reviewed the implementing procedures identified above and noted that there was no administrative document detailing the Cooper Nuclear Station's long-term program for monitoring erosion/corrosion related wall thinning of piping components nor was there an administrative document identifying assigned responsibilities for developing and implementing the long-term erosion/corrosion monitoring program. While there was no current formal administrative document detailing the erosion/corrosion monitoring program and associated assigned responsibilities, this was not a problem since an informal process was in place to provide guidance in these areas. The licensee noted that the development of a draft administrative document detailing the Cooper Nuclear Station erosion/corrosion monitoring program and assigning responsibilities had been delayed until after the 1995 refueling outage.

3.3 Program Implementation

Licensee representatives noted that the engineering programs department was responsible for implementing the erosion/corrosion monitoring program. The inspectors reviewed the methods which the licensee employed to determine the pipe and components to be inspected (i.e., the flow-accelerated corrosion wear rates, the documentation and calculations that supported the analysis, the examination data feedback to the analysis group, and the actions taken for degraded conditions). Items noted by the inspectors during this inspection are detailed below.

3.3.1 Analysis Program

The inspectors determined that the licensee used the CHECMATE family of codes along with other industry information and experience to identify and rank suspected locations in selected piping systems for inspection during the 1993 and 1995 refueling outages. However, the inspectors noted that the contractor erosion/corrosion coordinator currently involved in the licensee erosion/corrosion program had not received training in the use of the CHECMATE family of codes and performance of the associated CHECMATE model calculations. The licensee informed the inspectors that they were actively recruiting to permanently fill the erosion/corrosion coordinator position with some one who had experience and training in the implementation of the CHECMATE/CHECWORKS family of codes.

To increase the accuracy of the licensee's 1993 CHECMATE models to reflect plant performance for a specific system, the initial (Pass 1) 1993 CHECMATE model had to be calibrated. This calibration for a specific system is normally accomplished by taking all newly measured component wall thicknesses and wear, obtained from the 1993 refueling outage examinations, and incorporating them back into the Pass 1 CHECMATE model to obtain an improved Pass 2 CHECMATE model. The inspectors noted that as of November 9, 1995, the actual erosion/corrosion examination data obtained during the 1993 refueling outage had not been incorporated into the licensee's CHECMATE models to calibrate the models. While the failure to generate Pass 2 CHECMATE model examination results for specific piping systems indicated a weakness in program development, it was not a safety concern.

The licensee notified the inspectors that, for the current 1995 refueling outage, they were utilizing the WECCalc computer software, produced by VECTRA Technologies, to both manage and perform computerized evaluation of the 1995 erosion/corrosion data.

The inspectors noted that, in accordance with the applicable 1993 instructions in Procedure 3.10, "Erosion/Corrosion Induced Pipe Wall Thinning Inspection Program," Revision 3, plant generating years calculations, inspection results evaluations (Attachment 2), and minimum acceptable wall thickness calculations (Attachment 3) were generated on the basis of the actual wall thickness readings taken during the 1993 refueling outage. These calculations and evaluations were performed to quantitatively predict the remaining pipe wall thickness and the acceptable remaining in-service time. However, during review of these documents, the inspectors noted, that while a majority of the calculations for these documents were prepared in March and April 1993, the second party reviews for some of these documents were not signed off until November 1995. Also, as of November 7, 1995, the inspection results evaluations (Attachment 2 of Procedure 3.10) performed on March 20, 1994, for Components RF-E-8-2509-1 and RF-E-8-2509-2 had not received any signatures for the second party review. Revision 3 of Procedure 3.10 did not identify a time period for completion of the second party review of the 1993 refueling outage erosion/corrosion calculations and evaluations.

The inspectors identified a weakness in management's oversight of the implementation of the erosion/corrosion program on the basis that the licensee had not completed the second party reviews of the calculations and evaluations performed on the 1993 erosion/corrosion examination results, over 2 years after the performance of the 1993 examinations, and after the start of the current 1995 refueling outage.

The inspectors noted that the licensee was not trending erosion/corrosion examination results obtained during the 1988, 1989, 1990, 1991, and 1993 refueling outage examinations. While it was not a safety concern that the examination results were not trended, it was considered another weakness in implementation of a detailed erosion/corrosion monitoring program.

The inspectors determined that while the licensee was a member of the CHUG/CHECWORKS user's group, the licensee did not currently have any personnel actively involved in the group. The inspectors determined that the erosion/corrosion coordinator was aware of current industry experience and was implementing this experience in the licensee's current activities in developing their program. For example, the licensee had received, and was evaluating, CHUG information on a pipe failure in a heater drain system pipe at Millstone, Unit 2, on August 8, 1995.

3.3.2 Selection Criteria

The inspectors reviewed the licensee's selection criteria for determining which systems would be included in their flow-accelerated corrosion program. The inspectors observed that the licensee had established a pipe selection criteria which followed the guidelines contained in NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," and Generic Letter 89-08. The inspectors reviewed system parameters for portions of four systems (condensate, extraction steam, reactor feedwater, and heater drains) that were subject to examination.

The inspectors concluded from the sample that the selection criteria were being properly applied.

3.3.3 Data Input

The inspectors reviewed the computer code modeling and data input for portions of the selected systems to verify that correct data was placed into the CHECMATE calculation for the ranking of pipes. The inspectors concluded that the information was accurately entered into the equations, reviewed by a second person to minimize the probability of data input error, and that the results were consistent with the data provided.

3.3.4 Inspections

On June 12, 1992, the licensee issued a consolidated status of the erosion/corrosion inspection results. This status identified a total of approximately 200 sites for which either wall thickness readings taken during the original 1988 program baseline measurements or subsequent refueling outages were measured. Per the licensee's 1993 erosion/corrosion plans, approximately 130 components were scheduled for inspection during the 1993 refueling outage. The inspectors noted that the examination component index from the "Erosion & Corrosion Examination Services Report Spring 1993 Outage, Cooper Nuclear Station," Revision 0, prepared by General Electric Nuclear Energy, identified that approximately 360 erosion/corrosion examination sites were inspected during the 1993 refueling outage. The inspectors noted that the erosion/corrosion inspection plan, titled "1995 Refueling Outage Pipe Wall Monitoring Inspection Scope," Revision 1, dated August 10, 1995, identified that approximately 144 components had been selected for erosion/corrosion inspection during the current 1995 refueling outage. The licensee had not completed the erosion/corrosion examinations as of November 9, 1995.

The inspectors concluded that the number of examination sites inspected during the 1993 refueling outage, and the number of components scheduled for examination during the 1995 refueling outage, were consistent with the number of examination sites and components typically examined at other facilities.

The assigned erosion/corrosion coordinator had produced an inspection plan for each outage, listing examination site recommendations, based on the corrosion monitoring program plan and previous examination results. The inspectors noted that, except for the erosion/corrosion examinations performed during the 1993 refueling outage, a post-outage erosion/corrosion report documenting examination results and next outage repairs or replacement recommendations had been prepared after each outage. The inspectors noted that Revision 3 of Procedure 3.10 indicated a post-outage erosion/corrosion report, documenting inspection results and next outage repairs or replacement recommendations, was to be prepared after the completion of outage examinations. Revision 3 of Procedure 3.10 did not identify a time period for when a post-outage erosion/corrosion report had to be issued after the completion of an outage. The inspectors reviewed the 1992 post-outage erosion/corrosion report, and concluded that the 1992 examination results were reported satisfactorily

The fact that the licensee had not issued a post-outage erosion/corrosion report for the 1993 refueling outage examinations as of November 9, 1995, 2.5 years after the completion of the examinations, indicated a weakness in management oversight and implementation of the erosion/corrosion program.

3.3.5 Examinations Observed

The inspectors observed erosion/corrosion baseline examinations of a new 50.8 cm [20 in] diameter extraction steam piping elbow (1BS007C) and pipe (1BS007U) on November 7, 1995, and reexamination of a 45.7 cm [18 in] diameter reactor feedwater piping tee 1RF019C on November 8, 1995. The inspectors observed installation of initial permanent grid/transducer site "A1" markings, using low-stress stamps, on the new extraction steam piping. The inspectors noted that the contractor nondestructive examination personnel observed were knowledgeable and resolved any data acquisition problems in a competent and professional manner. The inspectors concluded that, in general, the observed erosion/corrosion examinations were performed acceptably and in accordance with the approved licensee procedures.

3.3.6 Nondestructive Examination Personnel

The inspectors reviewed Procedure 3.10 and the certifications for five contract nondestructive examination examiners performing erosion/corrosion activities during the current 1995 refueling outage. The inspectors confirmed that the latest procedures were used to perform the 1995 refueling outage flow-accelerated corrosion examinations, and that the licensee contractor nondestructive examination personnel performing the examinations were certified.

3.3.7 Material Repairs and Replacements

The inspectors reviewed several corrective actions initiated by the licensee as the result of identified flow-accelerated corrosion wear. The inspectors noted that the corrective actions were prepared and documented in accordance with established plant procedures.

The inspectors concluded that the licensee's program incorporated appropriate corrective actions for components with identified flow-accelerated corrosion wall thinning.

3.3.8 Program Management and Quality Assurance Oversight

The inspectors reviewed the management oversight of the licensee's erosion/corrosion monitoring program.

3.3.8.1 Program Responsibility

The inspectors observed that the licensee could not identify a current document that detailed responsibilities for administering the erosion/corrosion monitoring program. The licensee noted that they were currently developing a document that would detail the e responsibilities.

3.3.8.2 Erosion/Corrosion Program Oversight

During discussions with quality assurance personnel, the inspectors identified that the quality assurance organization had not performed any audits or surveillances of previous licensee erosion/corrosion program activities. The quality assurance organization had issued "Audit Scoping Plan No. ASP-217 Erosion/Corrosion," dated October 19, 1995, to perform an audit and surveillances of the erosion/corrosion monitoring activities associated with the 1995 refueling outage. As of November 7, 1995, however, the licensee had not completed any audits or surveillances of the erosion/corrosion monitoring activities.

Based on review of the above information, the inspectors concluded that the quality assurance organization had not been involved in the development of the current erosion/corrosion monitoring program. The inspectors noted that the currently scheduled quality assurance oversight activities of the erosion/corrosion monitoring program during the 1995 refueling outage, identified in Audit Scoping Plan ASP-217, were similar to those typically performed at other facilities.

3.3.8.4 Long-Term Strategy

The inspectors noted that the licensee's current erosion/corrosion procedures did not include a documented long-term strategy for reducing general erosion/corrosion wear rates as recommended by the Electric Power Research Institute guidelines. Upon completion of discussions with the licensee representatives, the inspectors concluded that the licensee was still developing their long-term strategy.

4 PLANT TOUR

The inspectors toured specific plant areas to verify materiel condition and housekeeping. The inspectors concluded that, in general, materiel condition was good, and housekeeping was fair, considering an outage was in progress.

5 FOLLOWUP (92902)

5.1 (Closed) Violation 298/9318-01: Inadequate Corrective Actions

5.1.1 Original NRC Violation

This violation pertained to the failure to resolve long-standing weaknesses in the establishment of adequate corrective actions and root causes for safety-related control room ventilation radiation monitors.

5.1.2 Licensee Action in Response

The licensee had completely revamped their corrective action program, establishing the condition reporting process. This process required condition reports to be written to document all equipment failures. The condition reporting process receives higher management level review.

The licensee had also replaced the radiation monitors with new digital monitors, which no longer had the same design characteristics that would cause failures similar to those experienced with the previous radiation monitors.

5.1.3 Inspector Action During the Present Inspection

The inspectors reviewed the licensee's Administrative Procedure 0.5, "Condition Reporting," Revision 3, and discussed the new radiation monitor design and modification package with the responsible engineer. Discussions with the engineer indicated that the design of the new digital radiation monitors were not susceptible to the same kinds of failures.

5.1.4 Conclusions

The inspector concluded that the corrective actions implemented by the licensee were appropriate for correcting the problems and minimizing recurrence of similar deficiencies.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

#*T. Ackerman, Inservice Inspection Engineer
*M. Boyce, Engineering Support Manager
J. Dillich, Maintenance Manager
#B. Fischer, Erosion/Corrosion Coordinator
J. Gausman, Plant Engineering Manager
#*F. Graham, Senior Engineering Manager
#*R. Godley, Nuclear Licensing and Safety Manager
#*J. Herron, Plant Manager
#*R. Jones, Senior Manager of Safety Assessment
#*J. Mueller, Site Manager
#G. Sen, Senior Staff Licensing Engineer
#R. Sessoms, Division Manager, Quality Assurance
#*M. Spencer, Engineering Programs Supervisor
*B. Victor, Licensing Engineer

1.2 NRC Personnel

#*M. Miller, Senior Resident Inspector

In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

* Denotes personnel that attended the debrief meeting on October 27, 1995.
# Denotes personnel that attended the exit meeting on November 9, 1995.

2 EXIT MEETING

An interim exit meeting was conducted on October 27, 1995, and the final exit meeting was conducted on November 9, 1995. During these meetings, the inspectors reviewed the scope and findings of this report. The licensee did not express a position on the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

DOCUMENTS REVIEWED

PROCEDURES

- Administrative Procedure 0.30, "ASME Section XI Repair/Replacement And Temporary Non-Code Repair Procedure," Revision 8
- Surveillance Procedure 6.1RHR.501, "ASME Section Periodic Pressure Test Of Class 2 RHR System Loop A," Revision 1
- Site Services Procedure 1.8, "Warehouse Issue And Return," Revision 17.1

INSPECTION RECORDS

Category B-M-2

- HPCI-MO-15 (valve)
- HPCI-MO-16 (valve)
- MS-RV-71B & 71D (valve)

Category B-K-1

- FWC-BK1-8
- MSA-BK1-13

Category CA-1A

- RHR-CA-1A
- RHR-CA-3A
- RHR-CA-3B

Category D-A

- ECST-TK-A4
- VR-DA-2

AUGMENTED INSPECTION REPORTS

- 12-300
- R-300
- D-211 (Core Spray Spargers)
- D-302 (Core Spray Internal piping)

ULTRASONIC CALIBRATION DATA/SUMMARY SHEET

CM-027	CM-025	CM-003	CM-002
R-042	R-082	R-081	R-041

MAINTENANCE WORK REQUEST

- 91-3330
- 93-1381
- 93-0457
- 95-36
- 95-3003

CONDITION REPORT

- 94-1123
- 95-1109