U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Northern States Power Company
Facility:	Prairie Island Nuclear Generating Plant
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EXECUTIVE SUMMARY

This inspection included a review of the licensee's implementation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The report covers a one week in-office review and a one week onsite inspection by regional and Office of Nuclear Reactor Regulation (NRR) inspectors.

Operations

The team concluded that operators' knowledge of the maintenance rule was limited but consistent with their responsibility for implementation of the maintenance rule. There was no indication that the maintenance rule detracted from the operators' ability to safely operate the plant. The team observed that additional training for control room shift supervisors would enhance shift supervisors' ability to deal with emergent work conditions.

Maintenance

- The licensee had generally identified the systems, structures, and components (SSCs) that were required to be within the scope of the maintenance rule. Documentation associated with the technical scoping basis was good. The licensee's scoping of structures was considered weak, in that all structures were not evaluated for inclusion in the maintenance rule program. The scoping of the fuel storage (dry cask) system within the rule was considered a strength. Four SSCs that were required to be included in scope, were not. This was considered a violation of the maintenance rule.

- The composition of the expert panel, and the qualifications and experience of the panel members were considered to be appropriate. The panel members exhibited good knowledge of the maintenance rule and the functions of the panel, but were not aware of the quorum or meeting frequency requirements. The panel members' PRA knowledge appeared to be limited and they mostly depended on the input from the PRA member. The expert panel was involved in several aspects of the maintenance rule implementation beyond those specified in NUMARC 93-01, and this was considered a strength.

- The inspectors considered the risk determination evaluations to be generally adequate. However, the nature of the inadequate bases for removal of two SSCs from the risk-significant category suggested that the expert panel was not fully cognizant of important aspects of the PRA modeling. The awareness of this modeling scope was considered an important part of the risk significance determinations. The licensee acknowledged the need to account for these modeling aspects in future risk determinations.

- The procedures for performing periodic evaluations met the requirements of the rule and the intent of the NUMARC implementing guidance. The team noted that the reports were comprehensive and would be a useful management tool for evaluating the effectiveness of maintenance.

- The team determined that the licensee had made appropriate efforts to balance reliability and availability for SSCs under the scope of the maintenance rule. However, the team determined that problems have been identified for accurately measuring reliability and availability. This could impact the licensee's efforts to balance reliability and availability which must be completed during the periodic assessment.

- The inspectors concluded that the use of the SAIC Equipment Out of Service system was an acceptable means of implementing the equipment out-of-service evaluation required by Section (a)(3) of the rule. The licensee acknowledged the need to inform Shift Managers about the inherent limitations of the current software.

- The establishment of performance criteria and goal setting was generally acceptable, with some notable exceptions. Performance criteria for reliability and unavailability of safety significant systems were incomplete in some cases. Specific performance criteria were not developed for onsite passive structures, and the performance goals set for the 480 VAC breaker pseudo system were not commensurate with plant specific safety considerations.

- The team noted that the licensee's maintenance rule data base, trending, and monitoring were especially well-developed. This was determined to be the result of an early and aggressive performance data collection program.

- The licensee had scoped buildings and enclosures as structures under the Rule. However, a lack of a defined structure monitoring program resulted in a lack of specific guidance for several areas. As a result, several structures (other than buildings or enclosures) were either not properly scoped or, if included within scope, did not have performance criteria or condition monitoring properly established.

- The team determined that the licensee was properly integrating industry-wide and site-specific operating experience into their maintenance rule program. This licensee used this information to establish goals and performance criteria, to identify generic industry functional failure concerns, to evaluate trends in SSC performance and to evaluate whether an SSC should be dispositioned from Section (a)(2) to Section (a)(1) of the rule.

- The material condition of the plant systems examined was excellent. With a few minor exceptions, the systems appeared to be well managed and were free of corrosion, oil, water, and steam leaks, and extraneous material.

<u>Quality Assurance (QA)</u>

- The team determined that with the limited number of self or independent assessments performed prior to the inspection, no conclusion could be drawn with regard to the effectiveness of the licensee's self-assessment of maintenance rule implementation.

Engineering

- The team noted that while system engineers were generally experienced and knowledgeable, their understanding of the maintenance rule and PRA was limited. However, considering the scope of maintenance rule responsibilities assigned to them by station management, the team concluded that their knowledge level was adequate.

Report Details

Summary of Plant Status

Unit 1 and Unit 2 were both operating at 100% power during the inspection.

Introduction

This inspection included a review of the licensee's implementation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The report covers a one week in-office and one week onsite inspection by regional and NRR inspectors.

I. Operations

04 Operator Knowledge and Performance

04.1 Operator Knowledge of Maintenance Rule

a. Inspection Scope (62706)

During the inspection of the implementation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," the team interviewed licensed reactor and senior reactor operators to determine if they understood the general requirements of the rule and their particular duties and responsibilities for its implementation.

b. Observations and Findings

The team determined that operator involvement with maintenance rule implementation was limited to the Reactor Operators' logging of equipment out-of-service times and the Shift Manager's use of the on-line risk assessment monitor. On learning that the Maintenance Rule Coordinator (MRC) frequently reviewed the logs for out-of-service times and extracted the data for unavailability records, the team focused on the Shift Managers' knowledge of the on-line risk assessment program.

The licensee used Administrative Work Instruction (AWI) 5 AWI 3.15.0, Plant Operations, Revision 4, to address the control of on-line maintenance activities. The shift managers' (i.e., qualified SROs) knowledge of this procedure was generally good. The procedure was recently updated to incorporate a new safety assessment tool, the Science Applications International Corporation (SAIC) Equipment Out of Service (EOOS) PRA-based safety assessment tool, which was recently placed on the shift manager's computer for use in evaluating EOOS.

The new tool was capable of calculating the conditional core damage frequency (CDF) for emergent work and abnormal EOOS configurations in a matter of seconds. By the end of the inspection, all shift managers had completed training on use of the SAIC EOOS PRA safety assessment tool; however, additional maintenance rule training was ongoing for shift supervisors on use of this new safety assessment tool. A review of the schedule revealed that seven of sixteen shift supervisors had completed maintenance rule training. Additional maintenance rule training was to be provided to all shift supervisors to communicate all emergent work conditions to the shift manager so that an adequate safety assessment for emergent work could be performed on the SAIC EOOS safety assessment computer software. The licensee stated that this new tool was an improvement over the previously used matrix method, which had been in use since the maintenance rule became effective.

The team observed that the shift supervisors (i.e., qualified SROs) in the control room were generally familiar with risk significant non-safety-related equipment at their plant (e.g., instrument air compressors, station blackout diesels). The shift supervisors were also familiar with work control and tagging practices for removing equipment from service. They also completed Limiting Condition for Operation (LCO) logs on the control room computer which tracked EOOS unavailability. The team observed that the shift supervisors were not fully aware of emergent work and its effect on the conditional CDF with other safety significant equipment that was OOS for maintenance.

The team noted that Procedure 5 AWI 3.15.0, Section 6.8.5, stated that the scope and duration of work on safety-significant equipment should be controlled through the weekly planning process. The team attended a licensee daily meeting and noted that the PRA group, the scheduling and planning group, and the shift manager all participated in daily and weekly meetings to discuss emergent work and EOOS issues.

c. Conclusions

The team concluded that operators' knowledge of the maintenance rule was limited but consistent with their responsibility for implementation of the maintenance rule. There was no indication that implementation of the maintenance rule detracted from the operators' ability to safely operate the plant. The team observed that additional training for control room shift supervisors would enhance shift supervisors' capability to respond to emergent work conditions that could affect the CDF profile for scheduled work. This was not required requalification training for the shift supervisors; however, the training could enhance communications between the shift supervisor and the shift manager which would enable the licensee to more effectively control on-line maintenance activities due to emergent work.

II. MAINTENANCE

M1 Conduct of Maintenance (62706)

The primary focus of the inspection was to verify that the licensee had implemented a maintenance monitoring program which satisfied the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of the Maintenance at Nuclear Power Plants," (the maintenance rule).

M1.1 SSCs Included Within the Scope of the Rule (62706)

a. Inspection Scope

The team reviewed the licensee's scoping documentation to determine if the appropriate SSCs were included within their maintenance rule program in accordance with 10 CFR 50.65(b). The team used inspection Procedure 62706, NUMARC 93-01, and Regulatory Guide 1.160 as references during the inspection.

b. Observations and Findings

The licensee's maintenance rule program was described in Procedure No. H24, "Maintenance Rule Program," Revision 1 (September 18, 1996). This program described the methodology used and a matrix to select the SSCs under the maintenance rule. The matrix considered whether the systems were safety related, failures could cause accidents or transients, were used in EOPs, failures could result in safety-related system failure, or failures could cause safety-related system actuation. Based on the results of these evaluations, lists were developed of systems within the scope of the maintenance rule and of systems excluded from the scope.

In general, the scoping of SSCs was good. The team reviewed the licensee's scoping documentation and determined that adequate justification for classification was available. The licensee considered about 100 SSCs in the scoping phase. Of these, 75 SSCs were placed within the scope of the maintenance rule. Six SSCs were considered risk significant and placed in the (a)(1) category. In addition, performance criteria were being conservatively established for 13 other SSCs which were not in the scope. The team noted that the licensee's scoping for structures was weak in that all structures were not evaluated for inclusion in the maintenance rule program. The team noted that the following four SSCs should have been included in the scope of the maintenance rule, but were not:

(1) Electrical Cable Trays: Some cable trays carried safety-related cables. The cable trays could be damaged due to misuse or could be subject to fires, if flammable materials were collected over the cable trays. The failure of the cable trays could lead to failure of the associated safety-related systems.

(2) Communication Systems: Prairie Island USAR, Section 10.3.8, describes the plant emergency communication systems, including a public address system (powered by an uninterruptible power supply), a sound powered system, and hand held portable radios. The plant Procedure 1C1.3.AOP1 (Revision 1) refers to communications regarding evacuation of the main control room and shutdown of the plant from outside the control room. The plant EOP procedures refer to AOP procedures. The team concluded that the in-plant communications systems were essential to mitigate accidents and to shut down the plant in an orderly manner in case of a condition necessitating such a shutdown.

(3) Circulating Water Traveling Screens: The plant maintenance rule system basis document for the circulating water (CW) system included CW pumps in

the scope, but not the CW traveling screens, stating that the screen plugging in this system was unlikely, since there was an external screen system. The licensee did not include the external CW system and its traveling screens in the scope of the maintenance rule, stating that the system did not have any maintenance rule functions. The CW traveling screens, if plugged with debris, could cause a loss of vacuum in the main condenser, thereby resulting in a reactor trip.

(4) Circulating Water Bay: The circulating water bay was not in the maintenance rule structures to be monitored. This bay included structures supporting the CW intake and protected the circulating water supply. As discussed above, the loss of circulating water could lead to a reactor trip.

10 CFR 50.65 states that the scope of the monitoring program shall include safety-related SSCs and non-safety-related SSCs that are: (a) relied upon to mitigate accidents or transients; (b) whose failure could prevent safety-related SSCs from fulfilling their safety-related function; and (c) whose failure could cause a reactor scram or actuation of a safety-related system. Contrary to the above, the four SSCs mentioned above were not included in the scope of the maintenance rule. The licensee's failure to include the above four SSCs in the scope under the maintenance rule was a violation of 10 CFR 50.65(b) (VIO 50-282/306-96012-01(DRS)).

The licensee's expert panel met during this inspection and decided to include the four SSCs in the maintenance rule scope.

The team noted that the licensee included the fuel storage (dry cask) system in the scope of the maintenance rule, even though this fuel storage was not under the scope of 10 CFR 50 and was covered under 10 CFR 72. The team considered this a very conservative decision.

c. Conclusions

The team concluded that the licensee had identified the SSCs (except as noted) that were required to be within the scope of the maintenance rule. Documentation of the technical basis for scoping decisions was well defined. The team noted the licensee's scoping of structures was weak in that all structures were not evaluated for inclusion in the maintenance rule program. The team identified a violation involving four SSCs that were required to be included within scope, but were not. The team also identified a strength in that the fuel storage (dry cask) system was included in the scope of the rule.

M1.2 Safety (Risk) Determination, Risk Ranking, and Expert Panel (62706)

a. Inspection Scope

Paragraph (a)(1) of the rule requires that goals be commensurate with safety. Additionally, implementation of the rule using the guidance contained in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," required that safety be taken into account when setting performance criteria and monitoring under paragraph (a)(2) of the rule. This safety consideration was to be used to determine if the SSC should be monitored at the system, train, or plant level. The team reviewed the methods and calculations that the licensee established for making these risk determinations. The team also reviewed the risk determinations that were made for the specific SSCs reviewed during this inspection. NUMARC 93-01 recommended the use of an expert panel to establish safety significance of SSCs by combining PRA insights with operations and maintenance experience, and to compensate for the limitations of PRA modeling and importance measures. The team reviewed the composition of the expert panel and experience and qualifications of its members. The team reviewed the licensee's expert panel process and the information available which documented the decisions made by the expert panel. The team interviewed several members of the expert panel to determine their knowledge of the maintenance rule and to understand the functioning of the panel.

b.1 <u>Observations and Findings on the Expert Panel</u>

The licensee used an expert panel process in conjunction with a PRA ranking methodology to determine the safety significance of SSCs within the scope of the maintenance rule. The expert panel included plant supervisors and other personnel experienced in PRA, operations, maintenance and engineering. Most of the panel members had a degree in engineering, SRO certification, and had between 9 and 28 years of nuclear power plant experience.

The team noted that the members of the panel demonstrated knowledge of the maintenance rule and the functions of the expert panel. However, the team noted that the PRA knowledge of non-PRA members was limited and these members heavily relied on the recommendations of the PRA members. The team also noted that the panel members were not aware of the quorum required for the panel meetings and the frequency of the panel meetings. These members relied on the maintenance rule coordinator on these matters.

The expert panel, referred to as the "Maintenance Rule Expert Review Group," reviewed the PRA results and approved the risk significant, in-scope and out-of-scope SSCs. The team noted that the expert panel was involved in several aspects of maintenance rule implementation, beyond those specified in NUMARC 93-01, such as:

- Approval of system performance criteria
- Review of periodic reports and recommendations
- Review of "get-well" programs
- Review of OOS management plan.

The team considered this a strength.

However, as noted in Section M 1.1 of this report, four SSCs, though required to be included in the scope, were not included. After this issue was raised by the team, the expert panel met and decided to include these SSCs in the scope.

c.1 Conclusions on Expert Panel

The team considered that the expert panel composition, qualifications, and experience were appropriate. The team concluded that the expert panel non-PRA members' knowledge of PRA was limited. The team noted that the panel functioned well, except in the omission of four SSCs from the scope of the maintenance rule. The team also considered the panel's involvement in several aspects of the maintenance rule implementation beyond those specified in NUMARC 93-01 a strength.

b.2 Observations and Findings on Risk Determinations

b.2.1 Analytical Risk Determining Methodology

The licensee completed their first determination of risk-significant SSCs for 10 CFR 50.65 in 1994 using the PRA model and software analysis tools which had been used to perform the Individual Plant Examination required by NRC Generic Letter 88-10. After these initial determinations were made, the licensee decided to change to the EPRI/SAIC Equipment Out-of-Service (EOOS) PRA software and simultaneously update their PRA model to reflect plant modifications being made to the emergency electrical power system for compliance with the Station Blackout Rule. A second risk-significance determination for 10 CFR 50.65 was completed in the spring of 1996 using the updated model and EOOS software, and was the analysis used to comply with the rule at the time of this inspection.

The inspectors noted that the licensee appeared to be making a good effort to maintain an accurate PRA model. In addition, the licensee was maintaining plant specific failure data for five of the most risk significant systems, including demand and operating time data. The PRA failure probabilities for the major components in these systems (e.g., pumps) were recalculated based on the previous 10 years of equipment performance data. The recalculated failure probabilities were expected to be used to update the PRA every two refueling outages.

For the Spring 1996 risk ranking, the licensee used EPRI TR-102266, Pipe Failure Study, to calculate reduced loss of coolant accident (LOCA) frequencies based on plant specific piping arrangements and features. A risk ranking was performed using both the original generic LOCA frequencies and the reduced LOCA frequencies. The use of the reduced LOCA frequencies revealed that certain core damage accident sequences, such as reactor coolant pump (RCP) seal LOCA, were being suppressed by the higher generic LOCA frequencies. The licensee used both risk rankings to identify risk-significant SSCs.

The Prairie Island Nuclear Generating Station has sustained one dual unit loss of offsite power (LOOP) and one steam generator tube rupture (SGTR) during plant operation to date. Initiating event frequencies for each of these events were calculated using IEEE 500 Bayesian update methodology which fitted a gamma distribution to a lognormal prior using a variation of the method of moments. The inaccuracy of this method becomes greater as the error factor of the lognormal distribution increases. Since the prior error factor used by the licensee was five, the inspector considered this an adequate approximation which increased the LOOP and SGTR frequencies assumed in the PRA.

The inspector noted that the truncation values used by the licensee ranged from 1E-9 for fault trees to about 1E-12 for the final sequence cutsets. These were considered appropriate based on being four to seven orders of magnitude below the CDF value.

b.2.2 Adequacy of Expert Panel Evaluations

During the 1994 risk ranking for the rule, the expert panel was presented PRA importance measure information which included those SSCs which fell below the NUMARC 93-01 importance measure criteria. Thus the expert panel was able to evaluate the need to place these SSCs in the risk significant category based on factors which had not been considered in the PRA. During the spring 1996 risk ranking, the expert panel was not presented with SSCs which were below the NUMARC criteria. However, the expert panel did add ten systems to the risk significant category, the bases for which were considered adequate. The lack of below-threshold SSC information during the spring 1996 risk ranking process was considered a weakness.

The expert panel removed four SSCs from the risk-significant list. For two of these SSCs (circulating water normal traveling screens and seal injection filters), the documented basis for removal was considered to be inadequate because it stated that other plant equipment or operator action had not been accounted for in the PRA, when in fact they had been. The licensee agreed that these bases were inadequate. The licensee restored the seal injection filters to the risk-significant category, and reevaluated the basis for maintaining the circulating water traveling screens in the non-risk category. These actions were evaluated and considered acceptable.

The inspectors noted that although the licensee brought in an independent review contractor for the 1994 risk ranking process, they had not had an independent review for the spring 1996 process. This was considered a weakness. The licensee acknowledged this and stated that an independent review was planned.

c.2 Conclusions on Risk Determinations

The inspectors considered the risk determination evaluations to be generally adequate. However, the nature of the inadequate bases for removal of two SSCs from the risk-significant category suggested that the expert panel was not fully cognizant of important aspects of the PRA modeling. The awareness of this modeling scope was an important part of the risk significance determinations. The licensee acknowledged the need to account for these modeling aspects in future risk determinations.

M1.3 (a)(3) Periodic Evaluations (62706)

a. Inspection Scope

Section (a)(3) of the rule requires that performance and condition monitoring activities and associated goals and preventive maintenance activities be evaluated, taking into account where practical, industry wide operating experience. This evaluation was required to be performed at least one time during each refueling cycle, not to exceed 24 months between evaluations. The team reviewed the procedural guidelines for these evaluations and several quarterly assessments and annual reports beginning in 1993 through 1995.

b. Observations and Findings

The licensee's instructions for conducting periodic evaluations were contained in Procedure H24, "Maintenance Rule Program," Revision 1. The procedure provided adequate guidance for preparing evaluations which would meet the requirements of 10 CFR 50.65 (a)(3) and the intent of NUMARC 93-01. After reviewing the completed quarterly assessments the team noted that each report was more comprehensive than the preceding one. This was also the case with the annual reports. The team also noted that the Maintenance Rule Coordinator was developing a monthly report to supplement the quarterly and annual evaluations. The team identified that the 1995 assessment did not contain a reliability and availability balance. This is discussed further in Section M1.4.

c. Conclusions

The procedures for performing periodic evaluations met the requirements of the rule and the intent of the NUMARC implementing guidance. The team noted that the reports were comprehensive and would be a useful management tool for evaluating the effectiveness of maintenance.

M1.4 (a)(3) Balancing Reliability and Unavailability (62706)

a. Inspection Scope

Paragraph (a)(3) of the maintenance rule requires that adjustments be made where necessary to assure that the objective of preventing failures through the performance of preventive maintenance was appropriately balanced against the objective of minimizing unavailability due to monitoring or preventive maintenance. The team reviewed the licensee's plans to ensure this evaluation was performed as required by the rule. The team also discussed these plans with the maintenance rule coordinator who was responsible for preparing this evaluation.

b. Observations and Findings

The licensee's approach for balancing availability and reliability was contained in H-24, "Maintenance Rule Program," Section 16, "Balancing Reliability and Availability," and Section 14.6, "Optimizing Availability and Reliability for SSCs." The team determined that the licensee had a process for completing a periodic assessment which was accomplished during the refueling cycle to include aspects of balancing reliability and availability.

Currently, the licensee has established unavailability performance criteria for several high safety (risk) significant SSCs (i.e., Emergency Diesel Generators (EDGs), Essential Service Water (ESW), Auxiliary Feedwater (AFW), Emergency Core Cooling Systems (ECCS), Compressed Air (CA), Residual Heat Removal (RHR), Chemical Volume Control System (CVCS), etc.). The performance criteria were roughly an order of magnitude less conservative that the unavailability assumed in the Probabilistic Risk Assessment (PRA). The licensee had evaluated these performance criteria to verify that there had not been a significant change in the CDF.

However, the team determined that the licensee did not take into account the number of functional failures per demands or per run time in service as a measure of reliability. The licensee chose to only monitor the number of failures per unit time period as a measure of reliability. This was not in accordance with the assumptions used in the PRA for establishing reliability values. Therefore, the licensee may not be using a valid reliability measurement in balancing reliability and unavailability. Meaningful estimates of reliability would necessitate information that incorporated failures per demands and per time in service as assumed within the PRA. The failure to set reliability performance criteria commensurate with safety for SSCs of high safety significance, where functional failures per unit time period was used as an indirect measure of reliability, could adversely affect the balancing process. This is discussed further in Section M1.6.b.b.2.

In addition, the team noted that Procedure H24, Section 2.0, Establishing Risk Significant Criteria, described the process used for tracking out-of-service time (OOS) for SSCs under the scope of the maintenance rule. In H24, page 12, paragraph 3, the last sentence states that "Since there are no options regarding surveillance testing inoperability, this time was not tracked." The team noted that not tracking unavailability times due to surveillance testing could impact the actual unavailability times for high safety significant and low safety significant standby SSCs. Based on this information, the team determined that for some SSCs the licensee may not be appropriately tracking total unavailability. The team found that this could also impact the periodic assessment for balancing reliability and availability. This is discussed further in Section M1.b.b.1.

The team also determined that the licensee did not perform balancing in the 1995 annual report. The licensee stated that balancing reliability and availability would be performed in the 1996 annual report. The team will follow up on this balancing issue pending review of the licensee's 1996 annual report and considered this an Inspector Follow Up Item (IFI 50-282/306-96012-02(DRS)).

c. <u>Conclusions</u>

The team determined that the licensee had made efforts to balance reliability and availability for SSCs under the scope of the maintenance rule. However, the team determined that problems have been identified for accurately measuring reliability and availability. This could impact the licensee's efforts to balance reliability and availability which must be completed during the periodic assessment. The licensee stated that adjustments to their yearly reports would be made to properly track SSC unavailability. Adjustment would also be made to establishing reliability goals and performance criteria. The licensee also stated that balancing reliability and availability would be properly performed in the 1996 annual report. The reliability and unavailability data would need to be more accurately captured to adequately perform balancing.

M1.5 (a)(3) On-line Maintenance Risk Assessments

a. Inspection Scope

Paragraph (a)(3) of the maintenance rule requires that when removing plant equipment from service the overall effect on performance of safety functions be taken into account. The guidance contained in NUMARC 93-01, endorsed by Regulatory Guide 1.160 revision 1 (January 1995), requires that an assessment method be developed to ensure that overall plant safety function capabilities were maintained when removing SSCs from service for preventive maintenance or monitoring. Until October 7, 1996, this assessment was performed at Prairie Island using a predetermined two-dimensional matrix. Subsequently, a computer-based probabilistic risk analysis tool was made available for Shift Manager use when needed. The inspectors reviewed the licensee's methods for performing these assessments.

b. Observations and Findings

The licensee implemented the use of the EPRI/SAIC Equipment Out-of-Service (EOOS) PRA software as of October 7, 1996 for on-line maintenance evaluations required by (a)(3) of the Rule. Only Shift Managers (SMs) were permitted to use EOOS and all SMs had received training in its use. The EOOS program was configured to perform cutset updates to a precalculated set of cutsets. This method was an approximation to the full solution to all fault trees and event trees, but had the advantage of much faster computation times. The EOOS user manual suggests that when the cutset update method was used that the cutsets include as many as possible which were generated from specific equipment out-of-service configurations. This brings additional cutsets above the truncation level which were important for these specific (expected) equipment configurations, thus making the analysis more accurate. Since the licensee was experiencing a limit of slightly more than 16,000 cutsets due to limitations of the cutset generating software, these equipment configuration-specific cutsets were not generated or added to the final cutset list used by EOOS. Under these circumstances, the accuracy of the EOOS calculation may degrade significantly as more equipment was assumed removed from service. The licensee's training program given to SMs did not include any cautions regarding limiting the number of assumed out-of-service equipment or components when performing this analysis. The use of EOOS was demonstrated by two SMs who were not aware of this potential for degraded accuracy in the EOOS calculation. This was considered a training weakness. The inspectors reviewed more than two months of recent control room operator logs and did not identify equipment out-of-service configurations with greater than two risk-significant components simultaneously out-of-service. Discussion with SMs indicated that such configurations were rare. Under these conditions, the use of EOOS as configured by the licensee was considered adequate.

The licensee implemented a shutdown risk control program via Procedure 5AWI 3.14.5 "Outage Management." This procedure used a checklist methodology to define degrees of defense-in-depth for several shutdown plant safety functions. This methodology was considered acceptable to meet the requirement for safety evaluations required by (a)(3).

The inspectors attended one daily plant operations meeting and noted that the PRA group was represented and contributed to the discussion.

c. Conclusions

The inspectors concluded that the use of EOOS was an acceptable means of implementing the equipment out-of-service evaluation required by (a)(3). The licensee acknowledged the need to inform SMs about the limitations of the EOOS analysis and stated that future upgrades to the speed of the computer hardware EOOS operates on would allow full fault tree and event tree analysis, thereby overcoming this limitation.

M1.6 (a)(1) Goal Setting and Monitoring and (a)(2) Preventive Maintenance

a. Inspection Scope

The team reviewed program documents in order to evaluate the process established to set goals and monitor under (a)(1) and to verify that preventive maintenance was effective under (a)(2) of the rule. The team also discussed the program with appropriate plant personnel. The team reviewed the following systems:

(a)(1) systems

EB - 480 VAC Electrical distribution
SA - Station Air
VC - Chemical and Volume Control System
EM - Event Monitoring System

(a)(2) systems

AF - Auxiliary Feedwater
RH - Residual Heat Removal
CI - Containment Isolation (pseudo) System
RM - Radiation Monitors
FW - Main Feedwater

The team reviewed each of these systems to verify that goals or performance criteria were established in accordance with safety, that industry wide operating experience was taken into consideration where practical, that appropriate monitoring and trending were being performed, and that corrective actions were taken when an SSC failed to meet its goal or performance criteria or experienced a maintenance preventible functional failure (MPFF). The team also reviewed performance criteria for SSCs not listed above.

The team reviewed the licensee's process to evaluate onsite passive structures for inclusion under the Maintenance Rule. Structures evaluated by the team included buildings, enclosures, storage tanks, earthen structures, and passive components and materials housed in the aforementioned. In addition, the team assessed by what means performance of structures determined to be within scope were monitored for degradation.

b. Observations and Findings

The team found that plant Procedure H24, "Maintenance Rule Program," provided appropriate guidelines for establishing performance criteria/goals for SSCs scoped under the Maintenance Rule. The licensee had established performance criteria and/or goals for all systems the licensee had designated within scope. The performance criteria/goals were documented and easily retrievable. System engineers were knowledgeable of the performance criteria/goals for their assigned systems. However, as discussed below, the team identified cases where unavailability or reliability related performance criteria had not been properly established for certain risk significant SSCs, performance criteria were not established for certain passive structures that were within scope, the tracking of unavailability times did not include surveillance testing out-of-service times, and that in some cases, actual performance criteria used by the MRC were more conservative than the program specified performance criteria.

b.1 Performance Criteria for Unavailability

Section 9.3.2 of NUMARC 93-01 recommended that risk significant SSC performance criteria be set to assure that the availability and reliability assumptions used in the risk determining analysis (i.e., PRA) were maintained. The inspectors evaluated the licensee's performance criteria to determine if they had been adequately set under (a)(2) of the Maintenance Rule consistent with the assumptions used to establish SSC safety significance. The team noted instances where the licensee had selected different values for unavailability and reliability performance criteria than what was used in the PRA.

The inspectors reviewed the 30 licensee specified risk significant SSCs, and identified that reliability performance criteria had been set (the adequacy of these reliability criteria is discussed below). However, the licensee had not set unavailability criteria for several risk significant SSCs. For some of these SSCs, any unavailability would have caused a plant trip or required a plant shutdown (e.g., DC power, main steam, reactor coolant, reactor vessel, steam generators, offsite power substation) and, as such, a plant-level performance criteria had been set. This was considered reasonable and acceptable. For other of these SSCs, their unavailability would make a front-line risk significant SSC inoperable (e.g., Boric Acid Storage Tank level instruments, EDG fuel oil, D1/D2 EDG ventilation, safeguards screen house ventilation), and thus unavailability would be accounted for by the front-line system which was rendered inoperable. This was also considered reasonable and acceptable.

However, the inspectors identified two of the 30 risk significant SSCs (safeguard buses 15/16 room coolers and safeguards chill water) for which maintenance unavailabilities had been assumed in the PRA, but for which no unavailability performance criteria had been set. In addition, the reactor protection and nuclear instrument systems were included as risk-significant SSCs, but had not been modeled as systems in the PRA. As multi-channel risk-significant systems, unavailability performance criteria (at the channel or component level) should have been established. However, at the time of the inspection, this had not been done.

The failure of the licensee to establish unavailability criteria for the aforementioned four systems was considered to be one example of a violation of 10 CFR 50.65(a)(2), being a failure to define performance monitoring criteria which demonstrate acceptable performance commensurate with safety (VIO 50-282/306096012-03a(DRS)).

The licensee used values for unavailability performance criteria which ranged from slightly greater than those assumed in the PRA up to about ten times the PRA assumptions. The licensee had performed a sensitivity analysis demonstrating that the use of the subject unavailability performance criteria would not have significantly impacted on total CDF (i.e., the simultaneous use of the Maintenance Rule unavailability criteria resulted in an approximately 28 percent increase in CDF).

The inspectors noted that the licensee had not performed an additional risk ranking to determine whether the ranking was adversely affected by these maximum assumptions. However, the inspectors considered it highly unlikely that actual plant equipment unavailabilities would simultaneously approach these maximum assumptions. Based on the above, the established unavailability performance criteria were considered adequate.

The inspectors also noted that programmatically, the licensee was not tracking all risk-significant and standby SSC unavailability times. SSC unavailability due to surveillance testing activities had been recently excluded from the overall tracking of unavailability. This situation could result in tracked unavailablities being less than actual unavailabilities so that any comparison made to associated performance criteria would be non-conservative. In addition, SSC reliability and unavailability would potentially not be properly balanced.

Although, not required programmatically, the Maintenance Rule coordinator was personally tracking all unavailability times including those associated with surveillance testing activities. When the concern was raised, the licensee committed to formally track surveillance related unavailability times as well.

b.2 Performance Criteria for Reliability

The licensee established, as reliability related performance criteria, two MPFFs per two year period for each of the 30 risk significant SSCs. However, at the time of the inspection, the licensee had not performed a sensitivity analysis that demonstrated that the performance criteria used for reliability preserved the assumptions used in the PRA or that the use of these reliability performance criteria did not have an adverse impact on risk ranking. The inspectors noted that there was no relationship established between these criteria and the failure probability assumptions in the PRA, since the number of function demands and/or equipment run times were not tracked. Thus, widely different SSC reliability estimates (probability of failure upon demand or per hour) could result from the same number of MPFFs in a specified time period if the number of demands or operating times varied between periods.

As such, the failure to couple the number of MPFFs to the failure probability assumptions in the PRA was considered to be the second example of a violation of 10 CFR 50.65(a)(2), failure to define performance monitoring criteria which demonstrate acceptable performance commensurate with safety (NOV 50-282/306-96012-03b(DRS)).

b.3 Performance Monitoring

Although not modeled in the PRA, the licensee designated certain systems as risk-significant based on the judgement of the expert panel. The inspectors found these additions acceptable. However, in some cases the documented performance criteria associated with the systems comprised system-level functional failures, where train/channel or component level criteria would have been more appropriate. For example, the reactor protection system (RPS) was designated a risk-significant SSC by the expert panel. The RPS had not been modeled in the PRA (a subcriticality basic event was used to represent an anticipated transient without scram condition). The RPS performance criteria were then defined to be two MPFFs in two years, where an MPFF was either a failure to trip the reactor or a failure to initiate emergency safeguards equipment.

However, evaluations of functional failures were actually being made for specific components of the RPS system. This was considered a documentation weakness in that the specified performance criteria did not monitor channel or component-level performance (as would be appropriate for a multi-channel risk significant system), although actual evaluation of failures was taking place at below the system functional level. The licensee acknowledged that the program documentation should be improved.

The team noted during review of the licensee's trending and monitoring programs that the licensee's maintenance rule data base was especially comprehensive. Detailed records of system performance, including maintenance rule performance criteria and goals were tabulated and generally available to the entire staff. During interviews, the MRC stated that LCO logs and trending were begun in 1992; performance trending was started in 1993. The intent was to track performance throughout the development of the maintenance rule program, rather than conduct a historical review over two cycles.

As discussed later in this section, the team noted that the three onsite condensate storage tanks, although scoped under the Rule were only monitored as part of the Auxiliary Feedwater (AF) system related to process flows to and from the tanks. The tank structures themselves were not included as part of a condition monitoring program for Maintenance Rule considerations. The team was also concerned that this issue was more generic and could involve other onsite storage tanks. At the end of the inspection, the licensee was evaluating the team's concerns.

b.4 Performance Goal Not Commensurate With Plant Specific Safety

The licensee had established an (a)(1) performance goal associated with the 480 VAC Electrical Breaker pseudo system that was solely based on an industry average reliability goal. However, a number of limitations in selection of the particular performance goal were evident to the team. Paramount was the fact that the goal was not related to plant specific performance as required by 10 CFR 50.65 (a)(1). Additionally, the goal could change non-conservatively as a result of a downward trend in overall industry performance. As such, the failure to develop performance goals related to plant specific performance was considered to be a violation of 10 CFR 50.65(a)(1), failure to define a reliability goal which demonstrated acceptable performance commensurate with safety (NOV 50-282/306-96012-04(DRS)).

b.5 Structures and Structure Monitoring

The inspectors reviewed Procedure H24, "Maintenance Rule Program," and other associated licensee programmatic controls to determine which onsite structures were evaluated for inclusion under the Rule. Additionally, a review of the performance criteria and monitoring established for structures within scope was performed. Discussions were held with engineering personnel to evaluate their familiarity with structure monitoring needs.

The team determined that: 1) the structure monitoring program lacked definition and specific guidance, 2) not all onsite structures were evaluated for possible inclusion under the Maintenance Rule, 3) some structures were erroneously excluded from scope, and 4) the condition of some structures that were determined to be within scope were not adequately monitored.

The licensee had conducted a detailed engineering review of civil structures onsite that had encompassed onsite buildings, concrete structures and structural steel members. The inspectors determined the civil review to be comprehensive for those areas evaluated, in particular for concrete buildings and enclosures. The civil engineer who had conducted the review had recommended that follow-up engineering walkdowns be performed every five years, and that in between, walkdowns by station personnel be conducted on a quarterly basis. The inspectors verified that the quarterly and 5-year walkdown activities were incorporated into the appropriate tracking mechanism(s). In addition, the guidance for conducting the 5-year walkdowns was specified in some detail. However, the guidance for conducting the quarterly walkdowns per preventive maintenance procedures PM 3586-1 and PM 3586-2, Plant Equipment Walkdowns for Radiologically Controlled Areas and for Non-Radiologically Controlled Areas, respectively, was very general and did not include any form of acceptance criteria.

Several onsite passive structures were not scoped under the Rule. The circulating water intake bay earthen structure was not evaluated for scoping under the Maintenance Rule. In addition, cable trays and risers were classified in general as part of the Electrical Distribution (ED) system. Although some cable trays carry safety-related cables and conductors, the licensee had excluded the ED system in total from scope. When this matter was brought to the licensee's attention, the expert panel placed the ED system within scope. At the conclusion of the inspection, the licensee was in process of evaluating the circulating water intake bay for possible inclusion under the Rule. The circulating water intake bay and cable tray scoping issues were discussed in Section M1.1.

The inspectors also noted that the three onsite condensate storage tanks were determined to be within scope and were included as part of the AF system. However, monitoring of the condition of the tank structures had not been established. Discussions with the AF system engineer revealed that performance monitoring of SSCs associated with the process flows to and from the tanks had been established but the condition of the tank structures themselves were not included as part of a monitoring program for Maintenance Rule considerations. In addition, the team determined that no specific performance criteria were established to assess the condition of structures. The licensee indicated that the 5-year civil engineering walkdown would identify degraded conditions but itself was not a performance criterion.

It was unclear at the conclusion of the inspection whether the lack of a defined structure monitoring program was in conformance with regulatory requirements or industry guidelines. As such, this was considered an unresolved item pending further NRC review (URI 50-282/306-96012-05(DRS)).

c. Conclusions

The establishment of performance criteria and goal setting was generally acceptable, with some notable exceptions. Performance criteria for reliability/unavailability for safety significant systems were incomplete in many cases. Specific performance criteria were not developed for onsite passive structures, and the performance goals set for the 480 VAC breaker pseudo system was not commensurate with plant specific safety considerations. The team noted that the licensee's data base, and trending and monitoring were especially well-developed. This was determined to be the result of an early and aggressive performance data collection program.

The licensee had adequately scoped buildings and enclosures as structures under the Rule. However, a lack of a defined structure monitoring program resulted in a lack of specific guidance intrinsic to the following areas: 1) No specific performance criteria were established for structures, 2) No acceptance criteria to gauge the condition of structures was developed, 3) no guidance was established for moving structures from the (a)(2) category to the (a)(1) category under the Rule. As a result, several structures (other than buildings or enclosures) were either not properly scoped or, if included within scope, did not have performance criteria or condition monitoring properly established.

M1.8 Use of Industry-wide Operating Experience

a. Inspection Scope

Paragraph (a)(1) of the rule states that goals shall be established commensurate with safety and, where practical, taking into account industry-wide operating experience. Paragraph (a)(3) of the rule states that performance and condition monitoring activities and associated goals and preventive maintenance activities shall be evaluated at least every refueling cycle. The evaluation shall be conducted taking into account industry-wide operating experience. The team reviewed the licensee's program to integrate industry operating experience (IOE) into their monitoring program for maintenance.

b. Observations and Findings on Use of Industry-wide Operating Experience

The licensee's Procedure H-24, "Maintenance Rule Program," Revision 1, Section 8, Industry Operating Experience and Section 14, Quarterly and Annual Maintenance Effectiveness Assessments, provided the administrative guidelines to integrate IOE into the licensee's monitoring program for maintenance.

The team also noted that Procedure H24, "Maintenance Rule Program," Revision 1, Section 6.3, Information Sources, specified that the following information sources should be used in preparing annual reports: (1) Quarterly Reports and Work Order History; (2) Nuclear Plant Reliability Data System (NPRDS); (3) NRC Analysis and Evaluation of Operational Data Reports; and (4) Modification or Work Orders.

The team determined that the licensee considered IOE from several different plants of similar age and design for comparison. The comparison plants included Kewaunee, Point Beach, Ginna, Beaver Valley, Surry, Robinson, Zion, Cook and others. The Maintenance Rule Coordinator (MRC) reviewed IOE information and summarized applicable information on a monthly and quarterly basis. Sources of information included (1) NRC Information Notices, (2) Institute of Nuclear Power Operations (INPO) Significant Event Reports, (3) INPO Significant Operating Event Reports, (4) NPRDS, and (5) INPO Operation and Maintenance Reports. This information was used to determine industry Functional Failures (FF) and Maintenance Preventible Functional Failures across similar plants within the industry.

The MRC also supplied IOE information to the system engineers as failures occurred within the industry on their systems. The system engineers provided feedback on similar components and procedures used to perform maintenance on their systems that were also used by other licensees. This feedback process was used to determine if there was a generic industry problem with a maintenance rule FF or MPFF issue.

The MRC also monitored site specific operating experience and trends equipment performance at Prairie Island. The trending data was summarized in annual reports and includes work order history. The trending data was used to evaluate whether an SSC was meeting its performance criteria, to identify any site specific generic concerns and to determine if the SSC should be considered for (a)(1) monitoring.

Systems indicating an upward trend in work order history were expected to provide the licensee with indications of a problem system. The MRC noted that the increasing trend in work order history on the feedwater system was indicative of problems with feedwater system regulating valves. Although no performance criteria were exceeded, the MRC was still evaluating whether to disposition the feedwater system to the (a)(1) monitoring category due to functional failure problems with the regulating valves which caused a reactor trip on March 9, 1996.

The team noted that an increasing maintenance work order history was also identified on the 480 volt system and the station air system, indicative of performance problems with these systems. The licensee had established goals to monitor these systems under (a)(1) of the maintenance rule.

c.2 Conclusions for Use of Industry wide Operating Experience

The team determined that the licensee was integrating industry-wide and site-specific operating experience into their maintenance rule program. This licensee used the IOE information to establish goals and performance criteria, to identify generic industry functional failure concerns, to evaluate trends in SSC performance and to evaluate whether an SSC should be dispositioned from (a)(2) to (a)(1). The team found that the licensee's approach to integrating IOE information into their program was acceptable.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 General System Review

a. Inspection Scope

The inspectors conducted a detailed examination of several systems from a maintenance rule perspective to assess the effectiveness of the licensee's program when it was applied to individual systems.

b.1 Observations and Findings for the Chemical Volume Control System (CVCS)

The team reviewed the established performance criteria for the CVCS system. The team found that the licensee established a reliability performance criterion of two functional failures per two years, an unavailability performance criterion of 600 hours per year per charging pump, and a plant level performance criterion of two LERs per year. The team found that the licensee did not establish functional failures per number of demands or per run time as additional reliability performance criteria for this high safety (risk) significant system.

The team reviewed non-conformances reports (NCRs) 2010427, 2010528, 2001221, 2010146, 2010189, 2010525, 2010416 and 2010475 associated with functional failure events that have occurred on the CVCS system.

The team found that the CVCS system charging pump train 23 had experienced an unavailability time of 819 hours which exceeded the performance criterion's value of 600 hours. Charging pump train 22 had experienced an unavailability time of

577 hours. The high unavailability was due to recent corrective maintenance which replaced the charging pump motor stator windings as well as other corrective and preventive maintenance. The licensee had already dispositioned the CVCS system to (a)(1) for different reasons (i.e., weld crack on charging pump discharge piping welds) prior to this high unavailability issue.

The team initially determined that CVCS system did not have new unavailability goals established for this (a)(1) system. In addition, there was no discussion in the licensee's documentation for establishing goals due to this high unavailability nor had corrective actions been implemented to correct the high unavailability problem. The team determined that the high unavailability was due to maintenance crews performing corrective maintenance once per eight hour shifts over a 24-hour period of time leaving the charging pump disassembled and inoperable for sixteen hours without conducting maintenance. The licensee stated that an expert panel meeting on October 10, 1996, had been conducted to discuss the unavailability problem with the charging pumps. Following that meeting, the licensee established an unavailability goal of 1200 hours per year per charging pump and verified that the new unavailability goal would not increase the CDF by a magnitude of 1 E-6. The team found that the newly established unavailability goal was acceptable.

The CVCS system was already an (a)(1) system due to a weld crack found on the discharge side of the charging pump near a check valve. The failure mode was due to cyclic vibration on the discharge piping. The licensee had a get-well program to install design changes for all charging pump discharge piping experiencing cyclic vibration. Charging pumps 22 and 23 were experiencing high cyclic vibration. The unit 1 charging pumps (i.e., 11, 12 and 13) were also experiencing some cyclic vibration but not as severe as the charging pumps on unit 2. The team found that the licensee's get-well program to correct maintenance rule functional failure problems with the CVCS system was acceptable.

b.2 Observations and Findings for the Residual Heat Removal (RHR) System

The team reviewed the performance criteria established for the RHR system and noted that the licensee had established two functional failures per two years as a reliability performance criterion and 72 hours per train per year as the unavailability performance criterion. The licensee did not establish functional failures per number of demands or per run time as additional reliability performance criteria for this high safety (risk) significant system.

The team reviewed NCRs 2010307 and 2010396 related to functional failures events associated with the RHR system. One NCR noted that woodruff keys sheared failing the actuator on an RHR heat exchanger outlet control valve CV-31236. The licensee determined that there were no key failures until the RHR system configuration was changed at mid-loop operation. With the new operating configuration, alternating RHR pumps resulted in high shaft torques values up to 255.2 ft-lbs in the flow control valves. The lower strength woodruff keys could only withstand a maximum torque value of 127.1 ft-lbs. This coupled with the fact that the original specified key material was incorrect in this configuration resulted in the key failure.

The licensee's corrective actions were to replace the woodruff keys on CV-31236 and 31235 with higher strength keys capable of withstanding torques values up to 331 ft-lbs. The team found that the licensee's corrective actions to eliminate this failure mode were acceptable.

b.3 Observations and Findings for the Containment Isolation (Pseudo) System

The team reviewed the performance criteria established for the containment isolation system and noted that the licensee had established a reliability performance criterion of two MPFFs per two years and a plant level performance criterion of two LERs per year.

The team reviewed local leak rate tests (LLRT) data on containment isolation valves. The LLRT 1995 and 1996 data revealed that the licensee was having problems with RCP seal water supply containment isolation valves (i.e., VC-8-5 and VC-8-4) not passing the LLRT. The licensee replaced and tested the valves with no additional problem. The team found the licensee's corrective actions acceptable.

The team also reviewed NCR 2001161 and Corrective Action Report (CAR) 2001161 which identified a Limitorque actuator on a containment sample valve with symptoms of decreasing stroke time and shortening of time between torque limit switch trip and dual light indications revealing that the valve was not closing. These valves also served as containment isolation valves when the valves were not open to perform their sampling function. The cause of the symptoms was discovered to be unthreading of the valve stem from the coupling plate within the valve yoke or motor mount. Unthreading was prevented by a hex jam nut and a lockwasher. The licensee identified that the configuration of the hex jam nut made it difficult to tighten the nut with normal tools. Future tightening would be accomplished using a special shop-fabricated tool.

The licensee identified this as a generic problem that could exist for all unit 1 and 2 sample valves (i.e., Unit 1: MV-32400, 32401, 32402, 32403, 32404, 32305; and Unit 2: MV 32406, 32407, 32408, 32409, 32410, 32411). The licensee planned on checking the tightness of all hex jam nuts during the next refueling outage for each unit. Adequate warning of problems with these valves would be identified during Section XI inservice testing. If the valve stems start to unscrew, dual indication would occur. The team determined that the licensee was taking appropriate corrective actions to eliminate this sample valve failure mode.

b.4 Observations and Findings for the 480 Volt AC Electrical System (EB)

This SSC was placed in (a)(1) category because of repeated starter failures due to sticking auxiliary contacts in GE motor control centers (MCC). Even though these were not repeat failures, the expert panel decided to place this SSC in a(1), due to numerous failures of the same type of components.

The breaker failures continued to occur. Sixteen non-conformance reports (NCRs) were issued since 1995 for safety-related 480 volt MCC failures. Eleven of these failures were for critical applications. Even though the root cause for the sticking of the auxiliary contacts was determined in December 1993 to be due to hardening of the original grease supplied by the manufacturer, the corrective action (changing grease to a different type) was not completed so far. There were still 47 safety-related 480 volt breakers to be maintained in Unit 1 and 45 safety-related breakers remaining in Unit 2. This corrective action issue was being handled by the NRC Resident Inspectors.

The goal set for this SSC was that the component specific failure rates for both units to be less than industry average. The team noted that this goal was not commensurate with the plant specific safety. Factors such as the total number of breakers in a plant, and the safety functions of the breakers should have been taken into account, rather than the industry average failure rate. This issue was addressed in Section M1.6 and was identified as a violation.

The team walked down some of the 480 volt electrical switchgear areas along with the system engineers and noted that the material condition of the equipments and the housekeeping were satisfactory.

b.5 Observations and Findings for the Radiation Monitoring System

This system was initially placed in (a)(1) category due to containment air monitor (CAM5) maintenance preventable failures, which resulted in three LERs. The goals set were that no additional CAM5 failures would occur and no further MPPFs for other components in the system resulting in an LER or a ventilation isolation.

This system was changed to category (a)(2) based on system performance, which met the set criteria for three surveillance periods. This non-safety-related SSC was recently taken out of the scope of the plant Technical Specifications.

The licensee decided to replace the belts on CAM5 on a quarterly basis, which minimized the potential failure of CAM5 due to belt failures. This amounted to setting the performance criteria to "run to failure," but this criterion was not clearly stated in the maintenance rule basis document. The team concluded that this was acceptable.

The team walked down the CAM5 area along with the system engineer and noted that this monitor was working satisfactorily.

b.6 Observations and Findings for the Event Monitoring System

This system was required for post-accident monitoring and was placed in category (a)(1), due to maintenance preventable failures of the hydrogen sensing subsystem, resulting in three LERs.

A goal was set that no additional MPPFs occur through 1997. The system performance criterion was established that the reliability of the system should not be less than two MPPFs per two years. System performance continued to be monitored as an (a)(1) system.

NRC issued a technical specification violation recently when the hydrogen sensors equipment was out-of-service for more than 72 hours. The Resident Inspectors were following up on this issue. A Part 21 notification was also issued by the manufacturer regarding the drying out of the grease on the hydrogen sensor.

c. Conclusions

The team concluded that the maintenance rule was being effectively applied to individual systems and that monitoring and trending were being satisfactorily implemented. Corrective actions were generally effective; however, some noted exceptions, which were referred to the resident inspector, were identified.

M2.2 Material Condition

a. Inspection Scope

In the course of verifying the implementation of the maintenance rule using Inspection Procedure 62706, the team performed walkdowns to examine the material condition of the systems listed in Section M1.6.

b. Observations and Findings

Except as noted in Section M2.1, the systems were free of corrosion, oil leaks, water leaks, trash, and based upon external condition, appeared to be well maintained.

c. Conclusions

In general, the material condition of the systems examined was excellent.

M7 Quality Assurance in Maintenance Activities

M7.1 Licensee Self-Assessments of the Maintenance Rule Program

a. Inspection Scope

The team reviewed the report of an assist visit by the Nuclear Energy Institute (NEI) which took place in early 1996. The team also met with representatives of the licensee's Quality Assurance organization to review the plans for an internal maintenance rule audit which was beginning at the conclusion of the team's inspection.

b. Observations and Findings

The NEI visit identified a few areas in need of management attention and highlighted areas which were implemented well. The plans for the licensee's internal maintenance rule audit appeared to be well organized and comprehensive. As discussed in Section M1.2, the team learned that the licensee did not provide for an independent peer review of the 1996 risk determination process although this was done for the 1994 effort.

c. Conclusions

The team determined that with the limited number of self or independent assessments performed prior to the inspection, no conclusion could be drawn with regard to the effectiveness of the licensee's self-assessment of maintenance rule implementation.

III. Engineering

E4 Engineering Staff Knowledge and Performance (62706)

E4.1 Engineers Knowledge of the Maintenance Rule

a. Inspection Scope (62706)

The team interviewed system engineers and managers to assess their understanding of PRA, the maintenance rule, and associated responsibilities.

b. Observations and Findings

System engineers were the focal point of the licensee's site engineering program and were involved in all aspects of system performance. The team found that system engineers, in general, were experienced and extremely knowledgeable about their assigned systems. The licensee's stated intent with regard to maintenance rule implementation by system engineers was to focus on the maintenance rule coordinator and minimize the impact. The reason was to avoid increasing an already substantial workload. Consequently, system engineer involvement with the maintenance rule was limited and knowledge of the rule was similarly limited. The team was able to determine through interviews that the system engineers understood the reason for the rule, the (a)(1) and (a)(2) ciassification concept, and the concepts of performance criteria and goals, With regard to PRA, most system engineers interviewed stated their knowledge of risk assessment was minimal.

c. Conclusions

The team noted that while system engineers were generally experienced and knowledgeable, their understanding of the maintenance rule and PRA was limited. However, considering the level of maintenance rule responsibilities assigned to them by station management, the team concluded that their knowledge level was adequate.

V. Management Meetings

X1 Exit Meeting Summary

The team discussed the progress of the inspection with licensee representatives on a daily basis and presented the inspection results to members of licensee management at the conclusion of the inspection on August 9, 1996. The licensee acknowledged the findings presented.

The team asked the licensee whether any materials examined during the inspection should be considered proprietary. The licensee indicated that the four program assessments provided to the team were proprietary information.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

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T. Amundson, Director, Generation Quality Services
J. Anderson, Operations Shift Manager
T. Asmos, Senior Engineer, PRA
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T. Breene, Superintendent Nuclear Engineering
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J. Curtis, Superintendent Electrical Engineering
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LIST OF INSPECTION PROCEDURES USED

IP 62706	Maintenance Rule
IP 40500	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 71707	Plant Operations

LIST OF ITEMS OPENED

50-282/306-96012-01(DRS)	(VIO)	SSC Scoping
50-282/306-96012-02(DRS)	(IFI)	Reliability/Unavailability Balance
50-282/306-96012-03a(DRS)	(VIO)	Lack of Unavailability Criteria
50-282/306-96012-03b(DRS)	(VIO)	Inappropriate Reliability Criteria
50-282/306-96012-04(DRS)	(VIO)	Inappropriate (a)(1) Goal
50-282/306-96012-05(DRS)	(URI)	Structure Monitoring Program

LIST OF ACRONYMS USED

AF	Auxiliary Feedwater
AOP	Abnormal Operating Procedure
AOT	Allowable Outage Time
CA	Compressed Air
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CVCS	Chemical Volume Control System
CW	Circulating Water
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling Systems
ED	Electrical Distribution
EDG	Emergency Diesel Generators
EOOS	Equipment Out of Service system
EOP	Emergency Operating Procedure
ESW	Emergency Service Water
EPRI	Electric Power Research Institute
FF	Functional Failure
FW	Feedwater
IEEE	Institute of Electrical and Electronics Engineers
IFI	Inspection Follow-up Item
INPO	Institute of Nuclear Plant Operations
IOE	Industry Operating Experience
IPE	Individual Plant Evaluation
LER	Licensee Event Report
LCO	Limiting Condition for Operation
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MPFF	Maintenance Preventable Functional Failure
MRC	Maintenance Rule Coordinator
MS	Main Steam

LIST OF ACRONYMS USED (continued)

NOV	Notice of Violation
NPRDS	Nuclear Plant Reliability Data System
NUMARC	Nuclear Management Resource Council
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
PCIS	Primary Containment Isolation System
PRA	Probabilistic Risk Assessment
PSA	Probabilistic Safety Assessment
QA	Quality Assurance
RCP	Reactor Coolant Pump
RHR	Residual Heat Removal
RPS	Reactor Protection System
SAIC	Science Applications International Corporation
SE	System Engineers
SGTR	Steam Generator Tube Rupture
SM	Shift Manager
SRO	Senior Reactor Operator
SSC	Structures, Systems or Components
TS	Technical Specifications
URI	Unresolved Item

LIST OF DOCUMENTS REVIEWED

H24, Revision 1, "Maintenance Rule Program"
5 AWI 3.15.0, Revision 4, "Plant Operations"
5 AWI 3.15.4, Revision 6, "Planned Outage Management"
5 AWI 3.17.1, Revision 1, "Root Cause Evaluation and corrective Action Guidance"
5 AWI 8.40, Revision 3, "Non-conformances"
Non-Conformance Reports (NCRs) on the CVCS System (i.e., 2010427, 2010528, 2001221, 2010146, 2010189, 2010525, 2010416, and 2010475)
NCRs on the RHR System (i.e., 2010307 and 2010396)
NCR on Containment Isolation (pseudo) System 2001161
Corrective Action Reports (CARs) on Containment Isolation (pseudo) System 2001161
Maintenance Rule System Specific Basis Document
Plant Engineering Handbook
Prairie Island Maintenance Rule Scope
Determination/Performance Criteria Summary
SP2088, Safety Injection Pumps Test
SP1355, Checking Chemical Feed and Auxiliary Feedwater Check Valves, Unit 1
PM 3586-1, Plant Equipment Walkdown-Radiologically Controlled Areas
PM 3586-2, Plant Equipment Walkdown-Non-Radiologically Controlled Areas
Memo, dtd. 9/3/96, from R. Peterson to J. Gonyeau, Re: Inspection of Plant Structures