October 29, 2003

Mr. Joseph Solymossy
Site Vice-President
Prairie Island Nuclear Generating Plant
Nuclear Management Company, LLC
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000282/2003005;
05000306/2003005

Dear Mr. Solymossy:

On September 30, 2003, the U. S. Nuclear Regulatory Commission (NRC) completed a baseline inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on October 2, 2003, with you and other members of your staff.

This inspection examined activities conducted under your license as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the inspectors identified one finding of very low safety significance that involved one violation of NRC requirements. However, because the violation was of very low safety significance and the issue was entered into your corrective action process, the NRC is treating the finding as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 801 Warrenville Road, Lisle, IL 60532-4351; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Prairie Island Nuclear Generating Plant.

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Sincerely,

/RA/

Patrick L. Louden, Chief
Branch 5
Division of Reactor Projects

Docket Nos. 50-282; 50-306
License Nos. DPR-42; DPR-60

Enclosure: Inspection Report 50-282/03005; 50-306/03005

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282; 50-306
License Nos:	DPR-42; DPR-60
Report No:	05000282/2003005; 05000306/2003005
Licensee:	Nuclear Management Company, LLC
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	July 1 through September 30, 2003
Inspectors:	J. Adams, Senior Resident Inspector D. Karjala, Resident Inspector T. Bilik, Reactor Engineer S. Burton, Senior Resident Inspector, Monticello P. Higgins, Reactor Engineer D. Jones, Reactor Engineer D. Nelson, Radiation Specialist B. Palagi, Senior Operations Engineer K. Walton, Examiner
Approved by:	Patrick L. Louden, Chief Branch 5 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000282/2003005, 05000306/2003005; 07/01/2003 - 09/30/2003; Prairie Island Nuclear Generating Plant, Units 1 & 2; Surveillance Testing.

This report covers a 3-month period of baseline resident inspection and announced baseline inspection of the Licensed Operator Requalification Program, Inservice Inspection Activities, and Radiation Protection. The inspection was conducted by the resident inspectors and inspectors from the Region III office. One Green finding and one associated Non-Cited Violation (NCV) was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Barriers

Green. A finding of very low safety significance was identified by inspectors during a plant status review of scheduled surveillance testing and daily work. The licensee concurrently scheduled the performance auxiliary building special ventilation system surveillance tests while conducting painting in areas of the auxiliary building that communicated with the ventilation system. The primary cause for the finding was inadequate procedural guidance in the licensee's procedure for the protection of pre-, absolute, and charcoal ventilation filters from contamination.

The finding was determined to be more than minor since if left uncorrected the condition would become a more significant safety concern as additional operation of the auxiliary building special ventilation system occurred concurrently with painting activities and would eventually have resulted in the inoperability of the auxiliary building special ventilation system filter units. The finding only represents a degradation of the radiological barrier function provided for the auxiliary building and has been determined to be a finding of very low safety significance. The finding was determined to be a violation 10 CFR Part 50, Appendix B, Criterion V, for a failure to include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. (Section 1R22)

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power throughout the inspection period except when power was reduced to about 93 percent on July 29, 2003, for repairs on heater drain tank pumps.

Unit 2 operated at or near full power from the beginning of the inspection period until August 20, 2003, when the unit entered coastdown operations for a refueling outage. The reactor was shut down for refueling on September 12, 2003, and remained shut down through the end of the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdowns

a. Inspection Scope

The inspectors performed two partial in-plant walkdowns of accessible portions of the redundant Unit 1 emergency diesel generator, a risk-significant mitigating system, and of the redundant instrument air compressors, risk significant equipment, the failure of which could result in an initiating event. Those walkdowns constituted completion of two partial system alignment inspections samples. The inspectors also utilized the documents listed in Attachment 1.

The inspectors conducted the in-plant walkdowns when the trains were of increased importance due to the unavailability of the alternate train. The inspectors utilized the applicable valve and electric breaker alignment checklists to verify that the components and required support systems were properly positioned to support the operation of the inspected systems. The inspectors also examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors reviewed outstanding work orders (WO) and action request (AR) corrective action program (CAP) items associated with the trains to identify any issues that could affect train function. The inspectors used the information in the appropriate sections of the Updated Safety Analysis Report (USAR) to determine the functional requirements of the systems. The inspectors verified the alignment of the following plant equipment:

- 122 and 123 Instrument Air Compressors while the 121 Instrument Air Compressor was unavailable due to preventative maintenance and testing on July 15, 2003; and
- Unit 1 emergency diesel generator D2 while the D1 was unavailable for maintenance on August 12, 2003.

b. Findings

No findings of significance were identified.

.2 Complete System Walkdowns

a. Inspection Scope

The inspectors performed a detailed in-plant walkdown of the alignment and condition of the Unit 2 125 volt direct current (DC) system, a risk significant system that provides power to risk significant mitigating system components. This inspection effort completed one complete system alignment inspection sample. As part of this inspection, the inspectors utilized the documents listed in Attachment 1.

The inspectors conducted in-plant walkdowns using the applicable electric breaker alignment checklists to verify that system components were properly positioned to support the operation of the inspected systems and to verify that the as-found system configuration matched the configuration specified in the system alignment checklist. The inspectors examined the material condition of the components, such as batteries, battery chargers, battery racks, cables, and electrical panels. The inspectors observed operating parameters of equipment to verify that there were no obvious deficiencies and examined all applicable outstanding design issues, temporary modifications, and operator workarounds. The inspectors verified that tagging clearances were appropriate and attached to the specified equipment. The inspectors reviewed outstanding WOs and AR CAP items associated with the trains to identify any issues that could affect train function. The inspectors referred to the Technical Specifications (TSs), USAR, and other design basis documents to determine the functional requirements of the systems and verified those functions could be performed if needed. In addition, the inspectors reviewed the AR CAP items to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

b. Findings

No findings of significance were identified.

1R05 Fire Protection Area Walkdowns (71111.05)

a. Inspection Scope

The inspectors conducted in-office and in-plant reviews of portions of the licensee’s Fire Hazards Analysis and Fire Strategies to verify consistency in the documented installed fire protection equipment and features in the fire protection areas listed below. The inspectors selected fire areas for inspection based on their overall contribution to internal fire risk, as documented in the Individual Plant Examination of External Events; their potential to impact equipment which could initiate a plant transient; or their impact on the plant’s ability to respond to a security event. The inspectors assessed the control of transient combustibles and ignition sources, the material and operational condition of fire protection systems and equipment, and the status of fire barriers. The following 10 areas were inspected by in-plant walkdowns completing 10 fire protection zone walkdown samples:

- Fire Area 13, Unit 1 and Unit 2 Control Room on July 09, 2003;
- Fire Area 18, Unit 1 and Unit 2 Cable Spreading Room on July 09, 2003;
- Fire Area 26, Unit 1 D2 Diesel Generator Room on July 10, 2003;

- Fire Area 69, Unit 1 Turbine Building Ground and Mezzanine Floors on July 09, 2003;
- Fire Area 101, Unit 2 D5 Diesel Generator Room on July 10, 2003;
- Fire Area 102, Unit 2 D6 Diesel Generator Room on July 10, 2003;
- Fire Area 33, Unit 1 11 Battery Room on September 25, 2003;
- Fire Area 34, Unit 1 12 Battery Room on September 25, 2003;
- Fire Area 22, 480V Safeguards Switchgear Room on September 25, 2003; and
- Fire Area 41, Screenhouse on September 26, 2003.

The inspectors also reviewed the AR CAP items listed in the Attachment to this report to verify that the licensee was identifying fire protection issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. The inspectors discussed fire protection issues with the fire protection engineer, operations personnel, and plant management.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

The inspectors conducted a review of the implementation of the licensee's inservice inspection program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries.

Specifically, the inspectors conducted an onsite and record review of the following three nondestructive examination activities to evaluate compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements and to verify that indications and defects were dispositioned in accordance with the ASME Code. The activities constituted two inspection samples:

1. Ultrasonic examination of a Unit 2 reactor coolant pump elbow to reactor coolant pump weld-6;
2. Liquid Penetrant examination of a Unit 2 reactor coolant system cross to 61 elbow weld-4; and
3. Liquid Penetrant examination of a Unit 2 reactor coolant system elbow to pipe weld-19.

The inspectors also reviewed the liquid penetrant examination of a Unit 1 safety injection pipe-elbow weld- 25 (indications found to be acceptable per ASME IWB 3514.3) from the previous outage with recordable indications that have been accepted by the licensee for continued service. The inspectors verified that the licensee's acceptance for continued service was in accordance with the ASME Code. This constituted one inspection sample.

The inspectors reviewed the radiographs of a Unit 2 reactor coolant pump loop B pressurizer spray valve (CV-31229) replacement, welds 1, 2, 3, 4, and 5, which were completed since the beginning of the previous refueling outage. The inspectors verified that the welding acceptance (e.g., radiography) and preservice examinations were performed in accordance with ASME Code requirements. This constituted one inspection sample.

The inspectors reviewed the removal and replacement of a Code Class 1, Unit 1 volume control system seal water injection check valve (an ASME Section XI Code replacement). The inspectors verified that the replacement met ASME Code requirements. This constituted one inspection sample.

The inspectors reviewed a sample of inservice inspection related problems documented in the licensee's corrective action program to assess conformance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. In addition, the inspectors verified that the licensee correctly assessed operating experience for applicability to the Inservice Inspection group.

The inspectors also reviewed In-situ Pressure Testing of Steam Generator Tubes; compared the estimated size and number of tube flaws detected during the current outage against the previous outage operational assessment predictions to assess the licensee's prediction capability; confirmed that the steam generator tube eddy current examination (ECT) scope and expansion criteria met technical specification requirements, Electric Power Research Institute (EPRI) Guidelines, and commitments made to the NRC; verified that the licensee has fully enveloped new degradation mechanisms in its analysis of extended conditions including operating concerns, and has taken appropriate corrective actions before plant startup (e.g., additional inspections, in-situ pressure testing, preventive tube plugging, etc.); confirmed that all areas of potential degradation (based on site-specific experience and industry experience) were inspected, especially areas which are known to represent potential ECT challenges (e.g., top-of-tubesheet, tube support plates, U-bends); confirmed that all repair processes used were approved in the technical specifications for use at the site; reviewed tube repair criteria; assessed whether the licensee identified a reasonable cause and developed corrective actions for leakage greater than three gallons per day; confirmed that the ECT probes and equipment were qualified for the expected types of tube degradation; assessed the site specific qualification of one or more techniques (e.g., equipment, data quality/noise issues, degradation mode); assessed corrective actions for loose parts or foreign material discovered on the secondary side of the steam generator; and reviewed the following two examples of eddy current data because questions arose regarding eddy current data analyses. The examples constituted one inspection sample:

1. Steam generator 22, row 10, column 53; and
2. Steam generator 22, row 3, column 49

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

The inspection activities described in Sections .1 through .7 below constitute one inspection sample, as part of the biennial review of licensed reactor operator requalification. The inspection activities described in Section .8 constitute one inspection sample, as part of the resident inspectors' quarterly review of licensed operator requalification training.

.1 Facility Operating History

a. Inspection Scope

The inspectors reviewed the plant's operating history from August 2001 through June 2003 to assess whether the Licensed Operator Requalification Training (LORT) program had addressed operator performance deficiencies noted at the plant.

b. Findings

No findings of significance were identified.

.2 Licensee Requalification Examinations

a. Inspection Scope

The inspectors reviewed the annual requalification operating and biennial written examination materials to evaluate general quality, construction, and difficulty level. The operating examination material reviewed consisted of three examinations each containing two dynamic simulator scenarios, seven job performance measures (JPMs), and biennial written examinations consisting of 40 open reference multiple-choice questions. The biennial examinations were conducted in July 2003. The inspectors reviewed the methodology for developing the examinations, including the LORT program two year sample plan, probabilistic risk assessment insights, previously identified operator performance deficiencies, and plant modifications. The inspectors also reviewed the licensee's program and assessed the level of examination material duplication during the current year annual examinations as compared to the previous year's annual examinations. Additionally, the inspectors interviewed members of the licensee's management, operations, and training staff, and discussed various aspects of the examination development.

b. Findings

No findings of significance were identified.

.3 Licensee Administration of Requalification Examinations

a. Inspection Scope

The inspectors observed the administration of the requalification operating test to assess the licensee's effectiveness in conducting the test and to assess the facility evaluators' ability to determine adequate performance using objective, measurable performance standards. The inspectors evaluated the performance of one shift crew in parallel with the facility evaluators during two dynamic simulator scenarios. In addition, the inspectors observed licensee evaluators administer twelve JPMs to five licensed operators. The inspectors observed the training staff personnel administer the operating test, including pre-examination briefings, observations of operator performance, and individual and crew evaluations after dynamic scenarios. The inspectors evaluated the ability of the simulator to support the examinations. A specific evaluation of simulator performance was conducted and documented under Section 1R11.7, “Conformance With Simulator Requirements Specified in 10 CFR 55.46,” of this report. The inspectors also reviewed the licensee’s overall examination security program.

b. Findings

No findings of significance were identified.

.4 Licensee Training Feedback System

a. Inspection Scope

The inspectors assessed the methods and effectiveness of the licensee’s processes for revising and maintaining its LORT program up to date, including the use of feedback from plant events and industry experience information. The inspectors interviewed licensee personnel (operators, instructors, training management, and operations management) and reviewed applicable licensee procedures. In addition, the inspectors reviewed the licensee’s quality assurance oversight activities, including licensee training department self-assessment reports, to evaluate the licensee’s ability to assess the effectiveness of its LORT program and to implement appropriate corrective actions.

b. Findings

No findings of significance were identified.

.5 Licensee Remedial Training Program

a. Inspection Scope

The inspectors assessed the adequacy and effectiveness of the remedial training conducted since the previous annual requalification examinations and the training planned for the current examination cycle to ensure that each addressed weaknesses in licensed operator or crew performance identified during training and plant operations. The inspectors reviewed remedial training procedures and individual remedial training plans, and interviewed licensee personnel (operators, instructors, and training management). In addition, the inspectors reviewed the licensee’s previous NRC annual examination cycle remediation packages for unsatisfactory operator performance on the operating test to ensure that remediation and subsequent re-evaluations were completed prior to returning individuals to licensed duties.

b. Findings

No findings of significance were identified.

.6 Conformance With Operator License Conditions

a. Inspection Scope

The inspectors reviewed the facility and individual operator licensees' conformance with the requirements of 10 CFR Part 55. The inspectors reviewed the facility licensee's program for maintaining active operator licenses and to assess compliance with 10 CFR 55.53 (e) and (f). The inspectors reviewed the procedural guidance and the process for tracking on-shift hours for licensed operators and the identification of control room positions that were granted credit for maintaining active operator licenses. The inspectors also reviewed eight licensed operators' medical records maintained by the facility's nurse and assessed compliance with the medical standards delineated in ANSI/ANS-3.4, "American National Standard Medical Certification and Monitoring of Personnel Requiring Operator Licenses for Nuclear Power Plants," and with 10 CFR 55.21 and 10 CFR 55.25. In addition, the inspectors reviewed the facility licensee's LORT program to assess compliance with the requalification program requirements as described by 10 CFR 55.59 (c).

b. Findings

No findings of significance were identified.

.7 Conformance With Simulator Requirements Specified in 10 CFR 55.46

a. Inspection Scope

The inspectors assessed the adequacy of the licensee's simulation facility (simulator) for use in operator licensing examinations and for satisfying experience requirements as prescribed in 10 CFR 55.46, "Simulation Facilities." The inspectors also reviewed a sample of simulator performance test records (i.e., transient tests, scenario test and discrepancy resolution validation test), simulator discrepancy and modification records, and the process for ensuring continued assurance of simulator fidelity in accordance with 10 CFR 55.46. The inspectors reviewed and evaluated the discrepancy process to ensure that simulator fidelity was maintained. Open simulator discrepancies were reviewed for importance relative to the impact on 10 CFR 55.45 and 55.59 operator actions as well as on nuclear and thermal hydraulic operating characteristics. Furthermore, the inspectors interviewed members of the licensee's simulator staff about the configuration control process and completed the Inspection Procedure (IP) 71111.11, Appendix C, checklist to evaluate whether the licensee's plant-referenced simulator was operating adequately as required by 10 CFR 55.46 (c) and (d).

b. Findings

No findings of significance were identified.

.8 Quarterly Review of Licensed Operator Requalification

a. Inspection Scope

During the week ending July 23, 2003, the inspectors performed a quarterly review of licensed operator requalification training completing one licensed operator requalification sample. As part of this inspection, the inspectors utilized the documents listed in Attachment 1. The inspectors assessed the licensee's effectiveness in evaluating the requalification program, ensuring that licensed individuals operate the facility safely and within the conditions of their license, and evaluated licensed operator mastery of high-risk operator actions. The inspection activities included, but were not limited to, a review of high risk activities, emergency plan performance, incorporation of lessons-learned, clarity and formality of communications, task prioritization, timeliness of actions, alarm response actions, control board operations, procedural adequacy and implementation, supervisory oversight, group dynamics, interpretations of technical specifications, simulator fidelity, and licensee critique of performance.

The inspectors observed a training crew during an as-found requalification examination in the plant's simulator facility. Crew performance was compared to licensee management expectations identified in the Administrative Work Instruction (AWI) listed in the Attachment to this report. The inspectors verified that the crew completed all the critical tasks for the scenario. For any weaknesses identified, the inspectors observed that the licensee evaluators noted the weaknesses and discussed them in the critique at the end of the session.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors completed one inspection sample, involving the residual heat removal system, to assess maintenance effectiveness. This system was designated as risk significant under the Maintenance Rule and had experienced multiple breaker position-indicating light failures. As part of this inspection, the inspectors reviewed the documents listed in the Attachment. The inspectors reviewed areas to assess maintenance effectiveness, including maintenance rule activities, work practices, and common cause issues. Inspection activities included, but were not limited to, the licensee's categorization of specific issues including evaluation of performance criteria, appropriate work practices, identification of common cause errors, extent of condition, and trending of key parameters. Additionally, the inspectors reviewed implementation of the Maintenance Rule (10 CFR 50.65) requirements, including a review of scoping, goal-setting, performance monitoring, short- and long-term corrective actions, functional failure determinations associated with reviewed condition reports, and current equipment performance status.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed three maintenance activities to review risk assessments and emergent work control completing three risk assessment and emergent work control inspection samples. As part of these inspections, the inspectors reviewed the documents listed in Attachment 1. During this review, the inspectors compared the licensee's risk management actions to those actions specified in the licensee's procedures for the assessment and management of risk associated with maintenance activities. The activities were chosen based on their potential impact on increasing the probability of an initiating event or impacting the operation of safety significant equipment. The inspectors verified that evaluation, planning, control, and performance of the work were done in a manner to reduce the risk and minimize the duration where practical, and that contingency plans were in place, when appropriate. The licensee's daily configuration risk assessment records, observations of shift turnover meetings, observations of daily plant status meetings, observations of shift outage meetings, and the documents listed at the end of this report were used by the inspectors to verify that the equipment configurations had been properly listed; that protected equipment had been identified and was being controlled where appropriate; and that significant aspects of plant risk were being communicated to the necessary personnel.

The inspectors reviewed the following planned and emergent maintenance activities:

- emergent maintenance required to repair pin hole leaks on the cooling water supply piping for emergency diesel generator D2 on July 1, 2003;
- emergent maintenance required due to degradation of the Unit 2 Volume Control Tank level instrumentation while emergency diesel generator D2 was inoperable on July 2, 2003; and
- planned maintenance on the Unit 2 Emergency Core Cooling System, Train A on July 9, 2003.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance Related to Non-Routine Plant Evolutions and Events (71111.14)

a. Inspection Scope

The inspectors observed the personnel performance of operators to one planned non-routine risk significant evolution performed during the Unit 2 refueling outage and two unplanned transient events completing three inspection samples to evaluate personnel performance related to non-routine plant evolutions and events. As part of this inspection, the inspectors reviewed the documents listed in the Attachment.

The inspectors reviewed the performance of operators and compared their actions to the specified actions contained in plant operating, annunciator response, and abnormal operating procedures. The inspectors independently assessed the causes for the transient events and compared inspector conclusions to the licensee's conclusions. The inspectors observed or conducted a post-event/evolution reviews of the following risk significant evolution and transient events:

- operator response to a transient event caused by a loss of power to of the CT-12 transformer and safety-related bus 26 on July 31, 2003;
- operator response to a reactor power transient event caused by the restoration of the Unit 1 letdown system on July 31, 2003; and
- Unit 2 reactor coolant system (RCS) draindown and reduced inventory operations evolution on September 15-17, 2003.

The inspectors also reviewed the AR CAP items listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. The inspectors verified that AR CAP documenting minor issues identified during the performance of these inspection activities were entered into the licensee's corrective action system for resolution.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Quarterly Operability Evaluation Reviews

a. Inspection Scope

The inspectors performed four operability evaluation assessments of degraded or non-conforming systems that potentially impacted mitigating systems or barrier integrity completing four operability evaluation inspection samples. As part of this inspection, the inspectors reviewed the documents listed in the Attachment. The inspectors completed these inspections through in-office review of documents and in-plant walkdowns of associated plant equipment. The inspectors assessed the following operability evaluations:

- operability recommendation (OPR) 000416, determination of maximum containment temperature for operability of containment," on July 2, 2003;
- operability recommendation OPR 000328, containment integrity of charging pump suction valves, SP-1366 (2366), on July 18, 2003;
- operability recommendation OPR 000432, leaking potheads on phases A and C of cooling tower transformer CT-12," on July 31, 2003; and
- prompt operability determination for AR CAP 031586, 12 auxiliary feedwater pump with suction pressure switch as-found calibration data greater than the as-found tolerance on September 30, 2003;

The inspectors reviewed the technical adequacy of the operability evaluations against TSs, USAR, and other design information; determined whether compensatory measures, if needed, were taken; and determined whether the evaluations were consistent with 5AWI 3.15.5, "Operability Determinations." The inspectors also reviewed the AR CAP items listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

b. Findings

No findings of significance were identified.

.2 Operability Evaluation Reviews With Unresolved Issues

a. Inspection Scope

The inspectors performed two operability evaluation assessments of degraded or non-conforming systems that potentially impacted mitigating systems or barrier integrity, completing two inspection samples. Both of these samples have issues that need to be resolved. As part of this inspection, the inspectors reviewed the documents listed in the Attachment. The inspectors conducted these inspections through in-office review of documents and in-plant walkdowns of associated plant equipment. The inspectors assessed the following operability evaluations:

- operability recommendation OPR 000433, obstructions blocking turbine and auxiliary building tornado blowout panels, on August 3, 2003; and
- operability recommendation OPR 000434, portions of the turbine and auxiliary buildings were designed for less than the required wind loads, on August 13, 2003.

The inspectors reviewed the technical adequacy of the operability evaluations against TSs, USAR, and other design information; determined whether compensatory measures, if needed, were taken; and determined whether the evaluations were consistent with 5AWI 3.15.5, "Operability Determinations." The inspectors also reviewed the AR CAP items listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

b. Findings

The inspectors noted that each of the operability evaluations referenced above refers to a Stevens and Associates Calculation 02Q0357-C-001, "Assessment of Old Service Building for Seismic and Tornado Loads." This calculation, performed in March 2003, provided a technical justification for the old service building to withstand both seismic and tornado loads in excess of original design. The operability recommendations (OPR 433 and 434) reference this calculation as a partial basis for the conclusion of operable but degraded and operable but non-conforming, respectively. The inspectors provided the calculation to a regional inspector for additional assessment. Based on the initial assessment, additional questions have been identified and additional follow up is required before the inspectors can determine that the licensee's conclusions are accurate and justified. Pending assessment of the licensee's response to the additional questions, this issue is identified as Unresolved Item (URI) 50-282/306/03-05-01.

1R16 Operator Workarounds (OWAs) (71111.16)

Review of Selected Workarounds

a. Inspection Scope

On July 23, 2003, inspectors performed an in-office review of an OWA associated with the 12 Boric Acid Transfer Pump (BATP). On June 21, 2003, the 12 BATP seal failed. The pump was removed from service and a portion of the associated piping was drained. This requires operators to manually control some heat trace circuits.

The inspectors reviewed the evaluation to determine whether the condition should be considered an OWA. A detailed list of the documents reviewed during this inspection is included at the end of this report.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors completed one permanent plant modification assessment inspection sample. As part of this inspection, the inspectors reviewed the documents listed in the Attachment. The inspectors performed this inspection through in-office review of documents and in-plant walkdowns of associated plant equipment.

The inspectors performed an assessment of changes made to the maximum allowable steam generator steam flow limit and the emergency response computer system high steam flow alarm set points. The inspectors verified that the design bases, licensing basis, and performance capability of related structures, systems or components were not degraded by the installation of the modification. The inspectors also verified that the modifications did not place the plant in an unsafe configuration. The inspection activities included, but were not limited to, a review of the design adequacy of the modification by performing a review, or partial review, of the modification’s impact on response time, control signals, equipment protection, operation, failure modes, and other related process requirements. The inspectors also reviewed the AR CAP items listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors completed two post-maintenance test assessment inspection samples. As part of this inspection, the inspectors reviewed the documents listed in the Attachment. The inspectors performed this inspection through in-office review of documents and in-plant walkdowns of associated plant equipment. The inspectors observed and assessed the post-maintenance testing activities for the following maintenance activities:

- 21 shield building ventilation system (SBVS) following removal of a undocumented temperature switch on July 8, 2003; and
- 11 steam generator power operated relief valve following the repair of current-to-pneumatic (I/P) converter on July 11, 2003.

The inspectors selected post-maintenance tests associated with important mitigating and barrier integrity systems to ensure that the testing was performed adequately, demonstrated that the maintenance was successful, and that operability of associated equipment and/or systems were restored. The inspectors reviewed the appropriate sections of the TSs, USAR, and maintenance documents to determine the systems' safety functions and the scope of the maintenance. The inspectors also reviewed the AR CAP items listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors observed the licensee's performance during the twenty-second Unit 2 refueling outage (2R22) conducted between September 12 and September 30, 2003. These inspection activities represent one refueling outage inspection sample.

This inspection consisted of a in-office review of the licensee's outage schedule, safe shutdown plan and administrative procedures governing the outage, periodic observations of equipment alignment, and plant and control room outage activities. Specifically, the inspectors determined whether the licensee effectively managed elements of shutdown risk pertaining to reactivity control, decay heat removal, inventory control, electrical power control, and containment integrity.

The inspectors completed in-plant observations of the following outage activities daily:

- attended outage management turnover meetings to verify that the current shutdown risk status was accurate, well understood, and adequately communicated;

- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- observed the operability of RCS instrumentation and compared channels and trains against one another;
- performed in-plant walkdowns to observe ongoing work activities; and
- conducted in-office reviews of selected issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance.

Additionally, the inspectors performed in-plant observations of the following specific activities:

- control room staff performing the Unit 2 shutdown and initial cooldown;
- operators aligning the RH system for shutdown cooling;
- control room staff draining reactor level to the reactor vessel to the flange;
- control room staff operations at reduced inventory conditions
- reactor pressure vessel (RPV) head lift;
- core unloading activities in the reactor containment, spent fuel pool, and control room;
- control room activities during core reload; and
- core load verification from containment.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed five surveillance test activities completing five surveillance test inspection samples. Observation of SP 2092 completed the quarterly baseline inspection requirement to observe an inservice testing activity for a risk significant pump or valve. Observation of SP 2072.5 completed the baseline inspection requirement to observe a containment isolation valve test each refueling cycle. Activities were selected based upon risk significance and the potential risk impact from an unidentified deficiency or performance degradation that a system, structure, or component could impose on the unit if the condition were left unresolved. As part of this inspection, the inspectors reviewed the documents listed in the Attachment. The inspectors also reviewed the AR CAP items listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

The inspectors performed in-plant observation of surveillance testing activities and in-office reviews of completed surveillance testing documentation to assess operational readiness and to ensure that risk-significant structures, systems, and components were capable of performing their intended safety function. The inspection activities included, but were not limited to, a review for preconditioning, integration of testing activities, applicability of acceptance criteria, test equipment calibration and control, procedural use, control of temporary modifications or jumpers required for test performance, documentation of test data, TS applicability, impact of testing relative to performance indicator reporting, and evaluation of test data.

The inspectors selected the following surveillance testing activities for review:

- Surveillance Procedure (SP) 1334, D1 Diesel Generator 18 Month 24 Hour Load Test on August 11 and 12, 2003;
- SP 1074A, Train A Auxiliary Building Special Ventilation Quarterly Test on August 21, 2003;
- SP 2083, Unit 2 Integrated Safety Injection Test with a Simulated Loss of Offsite Power on September 14, 2003;
- SP2092 Safety Injection Check Valve Testing on September 24 for Part B, September 29 for Part A, and September 29 for Part C; and
- SP 2072.5, Local Leakage Rate Test of Penetration 5 (Reactor Coolant Drain Tank Pump Discharge) on September 26, 2003.

b. Findings

Introduction: The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, having very low safety significance (Green) for the operation of the 121 auxiliary building special ventilation system (ABSVS) while painting in the containment spray pump rooms, an area that exhausts to the 121 ABSVS. The issue was considered to be NRC-identified since the inspectors questioned the practice allowed by the licensee's procedure.

Description: On August 28, 2003, the inspectors attended a daily work planning meeting as part of their routine plant status activities. During that meeting, the licensee discussed work activities for the day including SP 1074A, Train A Auxiliary Building Special Ventilation Quarterly (WO 0302325) and painting of the Unit 1 and Unit 2 containment spray pump rooms located on the 695 foot level of the auxiliary building. The inspectors asked the licensee if the containment spray pump rooms contained ventilation exhaust connections to the ABSVS and were told that the rooms were in the ABSVS ventilation zone. The inspectors expressed concerns regarding the effect that painting would have on the performance of the charcoal filter section of the ventilation system and were shown Maintenance Procedure D86, Protection of Pre-, Absolute, and Charcoal Ventilation Filters from Contamination. Section 7.1.1.A stated that application of non-water-based paints shall not exceed 500 square feet per day on the 695 foot level. The licensee indicated that the painters were aware of and complied with the limitation. The inspectors requested a basis or technical justification that supported the concurrent operation of the ABSVS and painting. The licensee was unable to provide the requested document but indicated that the procedure had been changed to allow limited painting based on their understanding of information presented at the 19th DOE [Department of Energy]/NRC Nuclear Air Cleaning Conference in May of 1987. The inspectors reviewed the proceedings and contacted the session speaker, an NRC Region I employee, to discuss the contents of the specific session. The session speaker told the inspectors that the session did not discuss or provide methodology for justifying operation of ventilation systems containing charcoal filters during periods of chemical use such as painting.

The licensee reviewed operating logs to determine the number of times these activities were performed concurrently and identified three such occasions, all associated with the

121 ABSVS. After a more detailed review of painting records, the licensee determined that on two of the three occasions the paint used was water-based paint. Only the painting conducted on July 28, 2003, used a solvent-based paint. The 121 ABSVS was operated for approximately 2.5 hours on that day and about 225 square feet of paint was applied.

Analysis: The inspectors concluded that without a technical basis for painting during ABSVS operation, maintenance procedure D86 was inadequate to ensure continued operability of the ABSVS. Even if a basis could have been provided that justified the area limitation on painting, as written, D86 would have allowed 500 square feet of painting daily. The cumulative effect of daily painting would eventually result in the inoperability of the affected ABSVS.

The inspectors determined that the licensee's failure to establish appropriate quantitative or qualitative acceptance criteria to ensure important activities have been satisfactorily accomplished was a performance deficiency warranting significance evaluation. The inspectors concluded that the finding was greater than minor since if left uncorrected the condition would become a more significant safety concern as additional operation of the ABSVS occurred concurrently with painting activities and could eventually result in the inoperability of the ABSVS.

The inspectors completed a significance determination of this issue using IMC 0609, "Significance Determination Process (SDP)," dated April 30, 2002, Appendix A. Since the finding only represented a degradation of the radiological barrier function provided for the auxiliary building, it was determined to be a finding of very low safety significance (Green). This finding was assigned to the barrier cornerstone for both units.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, requires, in part, that procedures include appropriate quantitative or qualitative acceptance criteria for determining important activities have been satisfactorily accomplished. Contrary to this, maintenance procedure D86, Protection of Pre-, Absolute, and Charcoal Ventilation Filters from Contamination indicates that it was acceptable to concurrently operate the 121 ABSVS while painting up 500 square feet per day in the Unit 1 and Unit 2 containment spray pump rooms located on the 695 foot elevation of the auxiliary building. Lacking a technical basis for the operation of the ABSVS while painting, the acceptance criteria in maintenance procedure D86 (i.e., the daily surface area limits for painting) cannot be considered as appropriate acceptance criteria. The licensee entered the finding into their corrective action program with AR CAP 032104 and AR CAP 032408. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program, this violation is being treated as a Non-Cited Violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000282/2003005-02; 05000306/2003005-02).

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors conducted an in-plant observation of the physical changes to the equipment and an in-office review of documentation associated with one temporary modification. The inspectors' effort completes one temporary modification inspection sample. As part of this inspection, the inspectors reviewed the documents listed in the

Attachment. The inspectors reviewed the temporary modification that blocked open the 11 containment chiller vanes to assess the impact of the modification on containment temperature control. The inspection activities included, but were not limited to, a review of design documents, safety screening documents, and USAR to determine that the temporary modification was consistent with modification documents, drawings and procedures. The inspectors also reviewed the post-installation test results to confirm that tests were satisfactory and the actual impact of the temporary modification on the permanent system and interfacing systems were adequately verified. The inspectors also reviewed the AR CAP items listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone:

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Review and Followup of Licensee Performance Indicator (PIs) for the Occupational Exposure Cornerstone

a. Inspection Scope

The inspectors reviewed the licensee's records affecting the performance indicators (PIs) related to occupational radiation safety. The review was conducted to determine whether the conditions affecting the PIs had been evaluated, and problems identified had been entered into the corrective action program for resolution. This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit (RWP) Reviews

a. Inspection Scope

The inspectors identified two radiologically significant work areas where unit two refueling outage number 22 (2R22) work was performed within high radiation areas and reviewed work packages which included associated licensee controls and surveys of these areas to determine if radiological controls including surveys, postings and barricades were acceptable. These work areas were walked down and surveyed using an NRC survey meter to verify that the prescribed RWP, procedure, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers were properly located.

The inspectors reviewed the RWPs and work packages associated with these and other high radiation work areas, and verified that work control instructions or control barriers had been specified. Technical Specification requirements affecting high radiation areas (HRAs) and locked high radiation areas (LHRAs) were used as the licensee's standards for the necessary barriers. Electronic dosimeter (ED) alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. The inspectors interviewed workers to verify that they were aware of the actions required when their ED noticeably malfunctions or alarms.

The inspectors reviewed the available RWPs for airborne radioactivity areas to determine if there was a potential for individual worker internal exposures to exceed 50 mrem Committed Effective Dose Equivalent (CEDE) (20 Derived Air Concentration-hours (DAC-hrs)). Barrier integrity and engineering controls performance such as high efficiency particulate air (HEPA) ventilation system operation were evaluated. The adequacy of the licensee's internal dose assessment process for internal exposures greater than 50 mrem CEDE was assessed. This review constituted two inspection samples.

The inspectors also completed one inspection sample involving the licensee's physical and programmatic controls for highly activated and/or contaminated materials (non-fuel) stored within the spent fuel pool and other storage pools.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's Radiation Protection Department self assessments, Nuclear Oversight Department assessments, Licensee Event Reports, and Nuclear Oversight Department observation reports related to the access control program to determine if identified problems were entered into the corrective action program for resolution. This included corrective action reports related to access controls. Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk. This review constituted two inspection samples.

The inspectors evaluated the licensee's process for problem identification, characterization, prioritization, and verified that problems were entered into the corrective action program and resolved. The inspectors focused on repetitive deficiencies and significant individual deficiencies to determine if the licensee's self-assessment activities were capable of identifying and addressing these deficiencies. This review constituted one inspection sample.

The inspectors reviewed licensee records to determine if PI events occurred since the last inspection. Since there were no Pis since the last inspection and there were no other occupational safety inspections scheduled for the remainder of 2003, this sample was considered completed. This review constituted one inspection sample.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors selected jobs being performed in high radiation areas (<1 R/hr) located in the Unit 2 Containment Building for observation of work activities that presented the greatest radiological risk to workers. This involved work that was estimated to result in the highest collective doses. The inspectors reviewed all radiological job requirements which included RWP requirements and work procedure requirements. Job performance was observed with respect to these requirements to verify that radiological conditions in the work area were adequately communicated to workers through prejob briefings and postings.

During job performance observations, the inspectors verified the adequacy of radiological controls including required surveys for system breach radiation, contamination, and airborne surveys); radiation protection job coverage which included audio and visual surveillance for remote job coverage, and contamination controls. This review constituted one inspection sample.

The inspectors reviewed radiological work in and around the Unit 2 Steam Generators. Because the work was performed in high dose rate areas where the dose gradients were significant, the review was conducted to evaluate the licensee's application of dosimetry to effectively monitor exposure to personnel and to verify that licensee controls were adequate. This review constituted one inspection sample.

b. Findings

No findings of significance were identified.

.5 High Risk Significant, High Dose Rate HRA and VHRA Controls

a. Inspection Scope

The inspectors held discussions with the Radiation Protection Manager (RPM) concerning high dose rate/high radiation area and very high radiation area controls and procedures including any procedural changes that had occurred since the last inspection in order to verify that any procedure modifications did not substantially reduce the effectiveness and level of worker protection. This review constituted one inspection sample.

The inspectors discussed controls, that were in place for special areas that have the potential to become VHRAs during certain plant operations, with radiation protection (RP) supervisors to determine if these plant operations required communication beforehand with the RP group, so as to allow corresponding timely actions to properly post and control the radiation hazards. During plant walkdowns, the posting and locking of all entrances to all LHRA, HRA, and VHRA were verified to be adequate. This review constituted two inspection samples.

b. Findings

No findings of significance were identified.

.6 Radiation Worker Performance

a. Inspection Scope

While observing work in the Unit 2 Containment Building the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements and verified that workers were aware of the significant radiological conditions in their workplace, the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present.

Radiological problem reports (condition reports) initiated since the last inspection were reviewed which found that the cause of the event was due to radiation worker errors to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matches the corrective action approach taken by the licensee to resolve the reported problems. These problems, along with planned or taken corrective actions were discussed with the RPM. This review constituted one inspection sample.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations in the Unit 2 Containment Building, the inspectors evaluated radiation protection technician performance with respect to radiation protection work requirements and verified that they were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and that their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

The inspectors reviewed the licensee’s radiological problem reports to identify events, the cause of which was radiation protection technician error to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matches the corrective action approach taken by the licensee to resolve the reported problems. This review constituted one inspection sample.

b. Findings

No findings of significance were identified.

2OS2 As-Low-As-Is-Reasonably-Achievable (ALARA) Planning and Controls (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed pertinent information regarding plant collective exposure history, current exposure trends, and ongoing or planned activities in order to assess current performance and exposure challenges. This included determining the plant's current three year rolling average collective exposure in order to help establish the resources required to complete this inspection attachment and to provide a perspective of significance for any resulting inspection finding assessment.

Site specific trends in collective exposures (using NUREG-0713 and plant historical data) and source-term were determined. Site specific procedures associated with maintaining occupational exposures ALARA and processes used to estimate and track work activity specific exposures were reviewed. This review constituted two inspection samples.

b. Findings

No findings of significance were identified.

.2 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the assumptions and basis for the current annual collective exposure estimate including procedures in order to verify the licensee's methodology for estimating work activity-specific exposures and the intended dose outcome. Dose rate and man-hour estimates were evaluated for reasonable accuracy. This review constituted one inspection sample.

b. Findings

No findings of significance were identified.

.3 Job Site Inspections and ALARA Control

a. Inspection Scope

The inspectors selected several work activities in high radiation areas located within the Unit 2 Containment Building for observation emphasizing work activities that presented the greatest radiological risk to workers. Work observed included work on the steam generators, preparation for the disassembly and lifting of the reactor head, and inspections of the under vessel penetrations. The licensee's use of ALARA controls for these work activities was evaluated. Specifically, the licensee's use of engineering controls to achieve dose reductions was evaluated to verify that procedures and controls were consistent with the licensee's ALARA reviews, that sufficient shielding of radiation sources was provided for and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding. This review constituted one inspection sample.

b. Findings

No findings of significance were identified.

.4 Declared Pregnant Workers

a. Inspection Scope

The inspectors reviewed dose records of declared pregnant workers for the current assessment period to verify that the exposure results and monitoring controls employed by the licensee complied with the requirements of 10 CFR Part 20. This review constituted one inspection sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

a. Inspection Scope

The inspectors reviewed the licensee submittals for three performance indicators (PI) for Prairie Island Units 1 and 2 completing six performance indicator verification inspection samples. The inspectors used PI guidance and definitions contained in Nuclear Energy Institute Document 99-02, Revision 2, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the PI data. As part of the inspection, the documents listed in Appendix 1 were utilized to evaluate the accuracy of PI data. The inspectors' review included, but was not limited to, conditions and data from logs, licensee event reports (LER), condition reports, and calculations for each PI specified. The inspectors also reviewed the AR CAP items listed in the Attachment to this report to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action program requirements.

The licensee's reporting of the following PIs were verified for the period of July 2002 through June 2003:

Unit 1

- Unplanned Power Changes per 7000 Critical Hours;
- Safety System Functional Failures; and
- RCS Specific Activity.

Unit 2

- Unplanned Power Changes per 7000 Critical Hours;
- Safety System Functional Failures; and
- RCS Specific Activity.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action system at an appropriate threshold, that adequate attention was given to timely corrective actions, and that adverse trends were identified and addressed. The inspectors also performed a screening review of items entered into the corrective action program and observed daily corrective action program meetings to identify conditions that warranted additional follow-up. Minor issues entered into the licensee's corrective action system as a result of inspectors' observations are included in the list of documents reviewed which are attached to this report.

.2 Biennial Sample Review

a. Inspection Scope

The inspectors reviewed a licensee self-assessment and four AR CAP items written to document deficiencies identified in the licensed operator training program. The licensee's self assessment included a review of the licensed operator training program two months prior to this inspection activity. The self-assessment and AR CAP items were reviewed to ensure that the full extent of the issues were identified, an appropriate evaluation was performed and the condition report was appropriately prioritized. The inspectors noted that the AR CAP items did not have corrective actions specified since the corrective actions had not yet been assigned. The inspectors determined that the corrective actions were enhancements to the existing licensed operator training program and not significant conditions adverse to quality per 10 CFR Part 50, Appendix B.

b. Findings

There were no findings of significance.

.3 Annual Sample Review

a. Inspection Scope

During the week ending July 19, 2003, the inspectors selected one corrective action program action request (AR CAP 031275) for detailed review completing one problem identification and resolution annual inspection sample. The AR CAP item was associated with the discovery of an undocumented temperature switch installed in the 21 SBVS system heater circuit. The licensee's actions taken to address the noted deficiency were reviewed by the inspectors to ensure that the full extent of the issue was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors evaluated the licensee's actions taken to address this issue against the requirements of the licensee's corrective action program as specified in Administrative Work Instruction 5AWI 16.0.0, Action Request Process; Performance Assessment Fleet Procedure FP-PA-ARP-01, Action Request Process; Administrative Work Instruction 5AWI 15.0.2, Work Order Codes; and 10 CFR Part 50, Appendix B.

b. Findings and Observations

The inspectors did not identify any findings associated with the review of this sample; however, the inspectors did identify problems with the assignment of work scheduling priorities of work orders generated to assess the extent of condition of other safety-related plant ventilation systems equipped with similar heater circuits. Specifically, the licensee established an appropriate priority level for the AR CAP item and the associated CA 006169, ACE 008741, and engineering work request (EWR) 006466, but the work orders generated to perform the work were assigned a priority six. A priority six designation indicated to work planners and schedulers that this work is desirable and does not affect plant safety or operation. For perspective, the licensee's work order (WO) priority levels range from a priority one (highest priority) to a priority seven (the lowest priority). The inspectors discussed the concern with the licensee and the licensee entered it into its corrective action program with AR CAP 032415. Additionally, the licensee appropriately reclassified the WO priorities and rescheduled the work in a time frame commensurate with the potential safety significance of the issue.

4OA3 Event Followup (71153)

(Closed) LER 50-306/03-001-00: Exceeded Technical Specification Completion Time

On March 14, 2003, the inspectors identified that the licensee inappropriately concluded that a pinhole leak on a ¾-inch cooling water line for the 21 component cooling water heat exchanger did not result in the inoperability of the associated cooling water header. The licensee identified the pin hole leak on January 25, 2003, and entered the condition into its corrective action program with AR CAP 027844. Subsequently, the shift manager's prompt operability determination concluded that the associated cooling water header remained operable. The condition was referred to engineering for additional operability review. On January 28, 2003, engineering personnel completed OPR 000376 that also concluded the associated components to be operable.

Prairie Island Technical Specification 3.7.8.B for one cooling water loop inoperable has a 72 hour limiting condition for operation. The licensee failed to declare the cooling water header inoperable and conduct appropriate repairs within the allowed outage time. Once the inappropriate licensee action was identified by inspectors, the licensee declared the cooling water header inoperable, isolated the affected component, and conducted a code repair within the allowed outage time. The licensee entered the deficiency into its corrective action program with AR CAP 028968 and conducted root cause evaluation (RCE) 000184.

The inspectors reviewed the licensee's root cause investigation, immediate corrective actions, and corrective actions to prevent recurrence to verify that the proposed corrective actions addressed the causes of the event. The inspectors also assessed the regulatory and risk significance of the issue. Because the pin hole leak was on the return side of the cooling water header and the condition was associated with a small (¾-inch) moderate energy ASME code class III cooling water line, a catastrophic failure of the line would not have resulted in a loss of safety function of the affected train, would not have resulted in internal flooding concerns based on the determined leak rate, and would not affected components of the redundant component cooling water train due to the physical separation between trains. Based on the inspectors' assessment of the event, the event was determined to be minor and of very low safety significance.

4OA5 Other Activities

.1 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (Temporary Instruction (TI) 2515/150, Rev. 2)

a. Inspection Scope

The objective of TI 2515/150, Rev. 2, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Order EA-03-009)," is to support the review of licensees' reactor pressure vessel (RPV) head and vessel head penetration (VHP) nozzle inspection activities that are implemented in accordance with the requirements of Order EA-03-009 (NRC Accession Number ML030410402), issued on February 11, 2003. The purpose of this TI is to validate whether a plant conforms to its inspection commitments and requirements during its next and subsequent refueling outages using procedures, equipment, and personnel that have been demonstrated to be effective in the detection and sizing of primary water stress corrosion cracking (PWSCC) in VHP nozzles and detection of RPV head wastage. As an ancillary benefit, this TI promotes information gathering to help the NRC staff identify and shape possible future regulatory positions, generic communications, and rulemaking.

The licensee performed Calculation ENG-ME-535, Revision1, to determine the effective degradation years (EDY) for the VHP nozzles in Units 1 and 2. In NRC Bulletin 2002-02, the EDY is used as a basis for establishing appropriate inspection programs for VHP nozzles based on increasing susceptibility to nozzle cracking with increasing EDY. For Unit 2, the licensee calculated an EDY of 10.9 years to September 12, 2003, (beginning of 2R22), which places the Unit in the primary water stress corrosion cracking susceptibility category of "Medium." Based on this EDY and the guidance on acceptable inspection programs discussed in Bulletin 2002-02, the licensee chose to perform a visual examination of the head during this refueling outage.

Summary

The licensee did not identify any leaking vessel head penetration nozzles.

b. Evaluation of Inspection Requirements

In accordance with requirements of TI 2515/150, Rev. 2, the inspectors evaluated and answered the following questions:

For each of the examination methods used during the outage, was the examination:

1. Performed by qualified and knowledgeable personnel?

Yes. The inspectors verified that the examination was performed by two qualified and certified Level II Visual Testing (VT)-2 examiners. In addition, the licensee's procedure (SP 1403 [2403]) required a review of EPRI Technical Report 1006899, "Visual Examination for Leakage of PWR Reactor Head Penetrations on Top of RPV Head, Revision 1 of 1006296, Includes Fall 2001 Inspection Results." The inspectors attended the pre-job "tailgate" which reviewed the procedural requirements, radiation and industrial safety aspects of the job.

2. Performed in accordance with demonstrated procedures?

No volumetric examinations were conducted during this outage. The inspectors verified that the bare metal visual examinations were conducted in accordance with SP 1403 [2403], Revision 0, "Reactor Vessel Closure Head Bare Metal Visual Examination," and that review of EPRI Technical Report 1006899,was included in the procedure as a sign off step to document its use as guidance for the examination.

3. Able to identify, disposition, and resolve deficiencies?

Yes. The inspectors concluded from the review of the documentation that the licensee had sufficient access to perform a direct visual examination of 100 percent of the bare metal of the reactor head as well as 360 degree coverage of each penetration with the aid of mirrors. No evidence of penetration leakage or boric acid accumulation was identified.

4. Capable of identifying the PWSCC and/or RPV head corrosion phenomena described in Order EA-03-009?

Yes. The inspectors determined through reviews of the documentation that the licensee's efforts were capable of detecting and characterizing VHP nozzle leakage and/or RPV head corrosion.

5. What was the condition of the reactor head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

The Prairie Island Nuclear Generating Plant pressure vessel head had block contoured vessel head insulation, consisting of mirror panels fabricated of 4-inch thick perforated metal block insulation with four viewing ports cut into the mirror insulation. The inspectors determined that the licensee had complete viewable coverage with the aid of mirrors. The as-found pressure vessel head condition was clean. A small amount of debris in the form of metal shavings and filings from the cutting of the viewing ports and canopy seal weld repair activities was noted; however, these did not obstruct the exam. No evidence of loose boric acid particles was identified.

6. Could small boron deposits, as described in Bulletin 01-01, be identified and characterized?

Yes. The inspectors determined through reviews of the inspection procedure and examination documentation, that small boron deposits, as described in the Bulletin 01-01, could be identified and characterized.

7. What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

There were no material deficiencies associated with the 41 VHP nozzles that were considered indicative of leakage.

8. What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?

None. The licensee had sufficient access to perform a direct visual examination with 360 degree coverage of each penetration.

9. What was the basis for the temperatures used in the susceptibility ranking calculation, were they plant-specific measurements, generic calculations (e.g., thermal hydraulic modeling, instrument uncertainties), etc.?

The basis for the temperatures used in the susceptibility ranking calculation is the Westinghouse calculation of the upper bulk mean fluid temperature (577.2 °F) of the vessel head area for use in loss-of-coolant accident analysis blowdown load calculations. To adjust for the plant specific cold leg temperature difference, as an input to Calculation ENG-ME-535, Revision 1(susceptibility ranking calculation), a head temperature of 580.2 °F was obtained by the addition of 3 °F to the upper bulk mean fluid temperature.

10. During non-visual examinations, was the disposition of indications consistent with the guidance provided in Appendix D of this TI? If not, was a more restrictive flaw evaluation guidance used?

No “non-visual examinations” were required during this outage.

11. Did procedures exist to identify potential boric acid leaks from pressure-retaining components above the RPV head?

Yes. The inspectors verified that visual examinations to detect potential boric acid leaks from pressure-retaining components above the RPV head were conducted in accordance with SP 1407 [2407], Revision 0, “Leakage Examination of Canopy Seals, Mechanical Joints, and Other Pressure Retaining Components on the Reactor Vessel Head.” The visual examination was performed by a qualified VT-2 examiner prior to beginning reactor vessel disassembly for refueling so that evidence of leakage from the connections was not disturbed.

12. Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components above the RPV head?

Yes. Procedure SP 1407 [2407], Revision 0, provides for initiating an action request to evaluate and disposition any leakage for boric acid corrosion potential. The reactor head vent orifice bypass (2RC-8-33) was identified as having evidence of boric acid leaking from the packing onto the pipe and the stainless steel mirror insulation over the reactor vessel head (CAP032850 and CE003707, 2R22 Startup Hold: Boric Acid Leakage from 2RC-8-33). The mirror insulation had a small dried puddle on it , which was not near any seams so it was not affecting the head. Work Order 0308529 repacked the reactor head vent orifice bypass valve, cleaned the boric acid, removed the old packing, cleaned the stuffing box, and repacked the valve. The head vent orifice bypass valve (2RC-8-33) was reinspected per SP 2070, RCS Integrity Test and SP 2168.23, Head Vent System Inservice Pressure Test. No evidence of leakage was noted during reinspection.

c. Findings

No findings of significance were identified.

.2 Temporary Instruction 2515/152, Reactor Pressure Vessel Lower Head Penetration (LHP) Nozzles (NRC Bulletin 2003-02)

a. Inspection Scope

On August 21, 2003, the NRC issued Bulletin 2003-02, “Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity.” The purpose of this Bulletin was to: (1) Advise pressurized water reactor (PWR) licensees that current methods of inspecting the RPV lower heads may need to be supplemented with additional measures (e.g., bare-metal visual inspections) to detect reactor coolant pressure boundary leakage; (2) request PWR addressees to provide the NRC with information related to inspections that have been or will be performed to verify the integrity of the RPV lower head penetrations, and; (3) require PWR addressees to provide a written response to the NRC in accordance with the provisions of 10 CFR 50.54(f).

The objective of TI 2515/152, “Reactor Pressure Vessel Lower Head Penetration Nozzles,” was to support the review of licensees’ RPV lower head penetration (LHP) inspection activities that are implemented in response to NRC Bulletin 2003-02. Specifically, licensee procedures, equipment, and personnel used for RPV LHP examinations were evaluated by the inspectors to confirm that the licensee met commitments associated with Bulletin 2003-02.

From September 16 through September 30, 2003, the inspectors performed a review of the licensee’s activities in response to commitments made to NRC Bulletin 2003-02. In response to Bulletin 2003-01, the licensee performed a visual examination of the vessel lower head and penetration nozzles. To assess the licensee’s efforts in conducting a visual examination of the RPV lower head and nozzles, the inspectors:

- performed an independent direct visual examination of the nozzle-to-head interface for portions of 12 of the 36 penetrations;
- observed the videotaped acquisition of the data for the visual examination of the head surface and penetrations;
- interviewed nondestructive examination personnel;
- reviewed the head inspection WO procedure which included the certification records for the nondestructive examination personnel
- reviewed the licensee's procedure for certification of visual examination personnel;
- reviewed the RPV lower head inspection videotapes; and
- reviewed the licensee's documentation of the evaluation of indications.

b. <u>Observations</u>

<u>Summary</u>

The licensee did not identify any RPV boundary leaks at the instrument nozzle penetrations or other locations, or boric acid deposits. The licensee identified 4 nozzles with indications at the nozzle-to-head interface which were not considered indications of leakage. The licensee identified some dried liquid stains. Samples of the stains were chemically analyzed and it was determined that the stains contained no boric acid, boron, or lithium, and were highly unlikely to have been caused by reactor coolant leakage.

<u>Evaluation of Inspection Requirements</u>

In accordance with requirements of TI 2515/152, the inspectors evaluated the following:

- the qualifications and certification of the inspection personnel and the inspection techniques;
- the examination procedure; and
- the performance of the inspection with attention to visual clarity, the method to track penetrations, and that deposits, debris, and insulation evaluation;

The inspectors independently observed the condition of 12 of the 36 nozzle penetrations and the RPV lower head area exposed by removed reflective metal insulation.

<u>Observations</u>

The licensee removed a five foot diameter circular section of reflective metal insulation from the center of the lower head to gain access for the inspection. This exposed 12 of the 36 instrument nozzles and penetrations. The remaining nozzles were accessible by way of a gap between the insulation and the lower head. The gap varied from an inch to about 3 inches, which permitted sufficient space for a robotic video camera. The examination methods included robotic video, still photography, and direct visual examination by certified VT-2 examiners. The examinations were recorded on video tape and disc. The acceptance criteria was a lack of any relevant indication of the type described in EPRI Technical Report 1006899, namely evidence of any leakage from the penetration to head interface, and lack of boric acid accumulations on the carbon steel head surfaces that may result in corrosion. Minor indications were identified on four penetrations. The indications were documented, evaluated, and dispositioned in the licensee corrective action program.

The reactor vessel, including the lower head, is coated with a zinc primer paint. The penetration nozzles are not painted. The paint thickness on the lower head did not interfere with the examiners ability to detect boric acid accumulations.

Some small dried liquid stains were identified and sampled by the licensee. The samples were analyzed and contained no boric acid or lithium. The stains were clearly the result of a source of liquid from above the nozzle penetrations. The chemical analysis indicated that the stains were old and highly unlikely to have been caused by reactor coolant leakage.

No boric acid deposits attributed to other sources of leakage through the pressure boundary were identified. No areas of the RPV lower head or LHP nozzles were obscured by debris, insulation, boric acid deposits, coatings or peeling coatings, or other obstructions, physical layout, and viewing obstructions. No anomalies, deficiencies, or discrepancies associated with the RCS structures or the examination process were identified.

<u>Evaluation of Inspection Requirements</u>

In accordance with requirements of TI 2515/152, the inspectors evaluated and answered the following questions:

a. For each of the examinations methods used during the outage, was the examination:

   1. Performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

      Yes. The licensee conducted a remote visual examination of the Unit 2 RPV lower head penetration interface and RPV lower head surface for leakage or boric acid deposits with knowledgeable staff members certified as VT-2 examiners in accordance with a procedure that meets the requirements and recommendations of ANSI N45.2.6 - 1978 using the method described by American Society for Nondestructive Testing Recommended Practice SNT-TC-1A. Additionally, the licensee inspection staff reviewed EPRI Technical Report 1006899, “Visual Examination for Leakage of PWR Rector Head Penetrations on Top of RPV Head” and photographs of the South Texas Project boric acid deposits found at the undervessel penetrations.

   2. Performed in accordance with demonstrated procedures?

      Yes. The licensee performed a demonstrated remote visual examination of the lower head and penetration nozzles using a pole mounted video camera in accordance with Work Order Procedure 0300435, “Perform Bare Metal Visual on Bottom of Reactor Vessel.” The licensee demonstrated that the capability of the remote camera system, lighting, and access were sufficient to detect a 1/32 inch black line on an 18 percent neutral gray card at the examination surface as required by the 1989 edition of ASME Section XI.

The inspectors observed the videotape data acquisition and reviewed the videotapes of the licensee’s examination and noted that it was consistent with the procedure requirements. The inspectors performed a direct visual inspection of 12 of the 36 penetrations. Based on this examination, the inspectors noted that the remote picture quality appeared to provide superior inspection to that available by direct visual examination, especially in those areas not directly accessible by the removal of insulation. The inspectors considered the quality of the remote visual examination to meet or exceed the requirement to resolve very small debris at the nozzle-to-head interfaces.

3. Able to identify, disposition, and resolve deficiencies?

   Yes. The licensee identified stains or small deposits at penetrations 10, 20, 31, and 36. Two samples of the deposited material were obtained and chemical analysis was performed. The analysis identified that no boron, boric acid, or lithium was present. The licensee determined that the deposits were old and highly unlikely to have been caused by reactor coolant leakage.

4. Capable of identifying pressure boundary leakage as described in the bulletin and/or RPV lower head corrosion?

   Yes. The licensee was able to gain access to the lower head by removal of a 5 foot diameter circular section of reflective insulation from the center of the lower head which exposed 12 of the 36 penetrations. The remainder of the penetrations were accessed by a pole-mounted video camera. The tip of the camera was articulated to allow access to the full diameter of the nozzle penetration. The camera picture quality provided superior resolution.

b. What was the physical condition of the RPV lower head (e.g., debris, insulation, dirt, boric acid deposits from other sources, physical layout, viewing obstructions)?

   The RPV, including the lower head, is painted with a gray zinc primer. The instrument penetration nozzles are not painted. The thickness of the primer paint would not prevent the identification of boric acid deposits. The RPV, including the lower head, are covered with a reflective metal insulation. There is a gap between the RPV head and the insulation. The gap varies from an inch up to approximately 3 inches. The only debris noted were stains from dried liquid that had flowed from above the nozzle penetrations down to the bottom of the lower head. The stains were sampled, chemically analyzed, and were highly unlikely to have been caused by reactor coolant leakage. The lower head and nozzles were free of dirt and boric acid deposits from other sources. Direct viewing was obstructed by the insulation. Viewing with the remote video camera was not obstructed.

c. Could small boric acid deposits, as described in the Bulletin 2003-02, be identified and characterized?

   Yes. If small boric acid deposits existed, the examination could have identified and characterized them. This was demonstrated by the identification and characterization of non-boric acid deposits. However, no boric acid deposits were found.

d. What material deficiencies (i.e., crack, corrosion, etc.) were identified that required repair?

   None. There were no cracks, corrosion, or other material deficiencies identified on the RPV, penetrations, nozzles, or instrument tubing. Following completion of the examination, replacement of the insulation, and removal of the scaffold, the instrument tubing, supports, and sump area walls were pressure washed.

e. What, if any, impediments to effective examinations, for each of the applied nondestructive examination method, were identified (e.g., insulation, instrumentation, nozzle distortion)?

   The licensee could not confirm that a 100 percent examination of the 360 degrees around each nozzle-to-head interface was conducted for 24 of the 36 nozzles due to the lack of reference marks and the capability of the camera equipment. The remote visual exam was necessary because of the access limitations for these nozzles created by the narrow gap between the mirror insulation and the lower RPV head.

f. Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components above the RPV lower head?

   Yes. The licensee collected two samples of deposit material and chemically analyzed the samples. The analysis identified that the deposits contained no boric acid, boron, or lithium. The analysis identified that the deposits were old and highly unlikely to have been caused by reactor coolant leakage.

c. <u>Findings</u>

No findings of significance were identified.

.3 <u>(Closed) Unresolved Item 50-282, 306/01-05-01</u>: Relay and Cable Spreading Room Carbon Dioxide System Acceptability. This issue was reviewed by the Office of Nuclear Reactor Regulation and the Office of General Counsel. The NRC staff’s acceptance of the CO_2 system was based on the licensee's commitment to satisfy the requirements of National Fire Protection Association (NFPA) 12-1972, "Carbon Dioxide Extinguishing Systems." The licensee's design basis for the relay and cable spreading room CO_2 system was 50 percent concentration with soak time of 15 minutes. The licensee recognized the weaknesses in the initial preoperational test and subsequently combined tracer gas testing and analysis to demonstrate that the system was capable of maintaining the required concentration and soak time. The NRC concluded that there was no specific prohibition to using analyses in combination with field test results to demonstrate operability for the CO_2 system. Since the 1972 edition of the standard did not explicitly require a full discharge test, no full discharge test was required. The NRC concluded that the licensing basis for the gaseous suppression system at Prairie Island has been met. This item is closed.

.4 (Closed) Unresolved Item 50-282, 306/01-05-02: Potential Violation of Section 186 Atomic Energy Act for Inaccurate Information. Since the NRC concluded that the licensing basis for the CO_2 system at Prairie Island has been met, there was no violation of NRC requirement for the information provided in the December 9, 1976 letter to the NRC. This item is closed.

4OA6 Meeting(s)

.1 Exit Meeting

The inspectors presented the inspection results to Mr. J. Solymossy and other members of licensee management at the conclusion of the inspection on October 3, 2003. Licensee representatives did not identify any materials examined during the inspection as proprietary in nature.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Biennial Operator Requalification Program Inspection with Mr. J. Solymossy on August 1, 2003.
- Radiation Protection Inspection - Access Control to Radiological Significant Areas and ALARA Planning and Controls with Mr. J. Solymossy on September 19, 2003.
- Inservice Inspection (IP 71111.08) and TI 2515/150, Rev. 2 with Mr. Mike Werner on September 25, 2003.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

J. Solymossy, Site Vice President
M. Werner, Plant Manager
T. Allen, Production Planning Manager
T. Bacon, Operations Training Supervisor
T. Downing, Engineering Supervisor
G. Eckholt, Regulatory Affairs Manager
B. Gillespie, Operations Manager
S. Hanson, ISI Coordinator
P. Huffman, Manager of System Engineering
A. Johnson, Radiation Protection Manager
T. Jones, NDE Technician Level III
J. Kivi, Licensing Engineer
M. Ladd, General Superintendent Plant Maintenance
J. Lash, Training Manager
S. McCall, NSSS Engineering Supervisor
M. McKeown, Manager of Design Engineering
S. Northard, Director of Engineering
K. Pederson, Reactor Vessel Program Engineer
A. Qualantone, Security Manager
S. Redner, Eddy Current Testing Program Manager
B. Stephens, Steam Generator Engineer
R. Womack, Manager of Engineering Programs
J. Wren, NDE Technician Level III

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-282, 306/03-05-01	URI	Resolution of Questions Associated with the Tornado Design of the Auxiliary and Turbine Buildings (Section 1R15)

Opened and Closed

50-282, 306/03-05-02	NCV	Failure To Establish Appropriate Quantitative/Qualitative Acceptance Criteria (Section 1R22)

Closed

50-282, 306/01-05-01	URI	Relay and Cable Spreading Room Carbon Dioxide System Acceptability (Section 4OA5.1)

50-282, 306/01-05-02	URI	Potential Violation of Section 186 Atomic Energy Act for Inaccurate Information (Section 4OA5.2)
50-306/03-001-00	LER	Exceeded Technical Specification Completion Time (Section 4OA3)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R04 Equipment Alignment

Partial System Walkdowns

122 and 123 Instrument Air Compressors

Procedure C34-2; System Prestart Checklist 122 Instrument Air Compressor; Revision 7
Procedure C34-2; System Prestart Checklist 123 Instrument Air Compressor; Revision 7
WO 0301147; P3505-2-123 123 Air Compressor 4000 Hour PM; March 20, 2003
WO 0303939; 122 Station Air Compressor Discharge Line Drain Hard to Operate; June 11, 2003
WO 0304046; Oil Leak on 123 Station Air Compressor; June 18, 2003
WO 0304051; 123 Station Air Compressor Unloader CV Leaks By, CV-31191; June 18, 2003

D2 Emergency Diesel Generator

Integrated Checklist C1.1.20.7-5, D2 Diesel Generator Valve Status, Revision 17
Integrated Checklist C1.1.20.7-6, D2 Diesel Generator Auxiliaries and Room Cooling Local Panels, Revision 8W
Integrated Checklist C1.1.20.7-7, D2 Diesel Generator Main Control Room Switch and Indicating Light Status, Revision 13
Integrated Checklist C1.1.20.7-7, D2 Diesel Generator Circuit Breakers and Panel Switches, Revision 16
AR CAP 031699; Unlabeled Valve Found During Steam Generator Blowdown Flash Tank Isolation
AR Corrective Action (CA) 006443; Unlabeled Valve Found During Steam Generator Blowdown Flash Tank Isolation

Complete System Walkdowns
Semiannual Complete System Walkdown of Unit 2 125 Volt DC

Prairie Island USAR, Section 8.5; DC Power Supply System; Revision 23
Prairie Island Technical Specifications, Sections 3.8.4, 3.8.5, and 3.8.6
Operating Procedure C20.9; Station Battery and DC Distribution System; Revision 24
Abnormal Operating Procedure 2C20.9 AOP1; Loss of Unit 2 Train A DC; Revision 4
Abnormal Operating Procedure 2C20.9 AOP2; Loss of Unit 2 Train B DC; Revision 4
Abnormal Operating Procedure 2C20.9 AOP3; Failure of the 21 Battery Charger; Revision 7
Abnormal Operating Procedure 2C20.9 AOP4; Failure of the 22 Battery Charger; Revision 8

Abnormal Operating Procedure 2C20.9 AOP5; Failure of the 21 Battery Fuse; Revision 4
Abnormal Operating Procedure 2C20.9 AOP6; Failure of the 22 Battery Fuse; Revision 3
Integrated Checklist C1.1.20.9; DC Distribution; Revision 17
Prairie Island Active Temporary Modification List as of July 15, 2003
Prairie Island Plant Equipment Out-of-Service List as of July 15, 2003
Prairie Island Operator Workaround List as of July 15, 2003
Design Basis Document DBD Sys-20.9; DC Auxiliaries System; Revision 3
Emergency Procedure 2ECA-0.0; Unit 2 Loss of All AC Power; Revision 17
AR CAP 029239;Lead Calcium Battery Information for Safeguards Batteries 11, 12, 21, and 22; March 25, 2003
AR CAP 029240; Color Coding for Battery Cables 11, 12, 21, and 22; March 25, 2003
AR CAP 030531; Many of the DC System Battery SPs and TPs [Test Procedures] Need Revision or Additions; May 28, 2003
AR CAP 030956; 21 Battery Room Special Exhaust Fan Belt Replacement; June 19, 2003

1R05 Fire Protection

Fire Zone Walkdowns

Plant Safety Procedure F5, Appendix A; Fire Strategies for Fire Areas 13 (Revision 7), 18 (Revision 11), 22 (Revision 7), 26 (Revision 10), 33 (Revision 7), 34 (Revision 7), 41B (Revision 8), 69 (Revision 10), 101 (Revision 11), and 102 (Revision 11)
Plant Safety Procedure F5, Appendix F; Fire Hazard Analysis for Fire Areas;13, 18, 22, 26, 33, 34, 41B, 69, 101, and 102 Revision 17
Individual Plant Examination of External Events NSPLMI-96001, Appendix B; Internal Fires Analysis; Revision 2
AR CAP 028508, Fire Dampers to Auxiliary Feedwater Pump Room, February 25, 2003
Prairie Island Safety Evaluation Report date September 6, 1979, Section 5.10
AR CAP 023400, Large Amount of Combustible Trash Stored in Vital Area, May 7, 2002
OTH 001089, Large Amount of Combustible Trash Stored in Vital Area, May 8, 2002
AR CAP 024613, Potential Fire Loading Issue with Plastic Drums, August 12, 2002
CE 000769, Potential Fire Loading Issue with Plastic Drums, August 13, 2002
OTH 002194, Potential Fire Loading Issue with Plastic Drums, September 9, 2002
AR CAP 023869, Evaluate Applicability of Temporary Instruction 00-111 Issued 11/19/00, June 19, 2002
CA 001450, Evaluate Applicability of Temporary Instruction 00-18 Issued 03/18/00, June 19, 2002
CE 000448, Evaluate Applicability of Temporary Instruction 00-111 Issued 11/19/00, June 19, 2002
OTH 000128, Converted Issue # 20006187 - Change Fire Protection Zone 101 to Provide Control Room Alarm vs. Trouble to Ensure an Actuated Deluge Valve Identified Promptly, December 03, 2002

1R08 Inservice Inspection Activities

SWI NDE-PT-1; Solvent Removable; Visible Dye Penetrant Examination; dated July 17, 2003

SWI NDE-UT-11; Ultrasonic Examination of Cast Stainless Main Coolant Pipe Welds; dated August 18, 2003
CAP 014098; OEA 2002-308 Safety Injection Tank Leak
CAP 013908; ASME Section XI Appendix VIII Examination of Dissimilar Metal Welds

1R11 Licensed Operator Requalification Program

Prairie Island 2003 Written and Operating Requalification Examinations for Weeks 1, 2, and 3
Prairie Island License Requalification Training P9100; Training Program Description; Revision 18
License Requalification Examination Development and Administration; Training Procedure No. 37; Revision 13
Prairie Island Training Center Procedure 1; Design Change Review; Revision 5
Prairie Island Training Center Procedure 2; Simulator Change Process; Revision 8
Prairie Island Training Center Procedure 20; Simulator Operability Testing; Revision 2
Self Assessment of License Operator Requalification; April 30, 2003 - May 3, 2003
Nuclear Oversight Observation Report No. 2003-002-6-028; June 18, 2003
License Operator Requalification Self-Assessment 25504; April 21, 2003
Operations Department Annual Performance Self Assessment 23037; December 17, 2002
Prairie Island Training Center Annual Simulator Operability Test - Steady State Testing-Part 1.1 100 Percent Power, Test Reports; dated January 7, 2003, December 13,2001, and January 31,2001
AR CAP 031481; Simulator Hardware Problem; July21, 2003
AR CAP 031098; No Formal Process for License Operators to Regain Proficiency; June 27, 2003
AR CAP 029924; Potential NRC Exam Security Compromise; April 24, 2003
AR CAP 029673; Unrecognized Minor Change in Operator License Conditions; April 11, 2003
5AWI 3.15.0; Plant Operation; Revision 14

1R12 Maintenance Rule Implementation

5AWI 3.2.10; Investigation and Troubleshooting; Revision 8
WO 0303935; 21 residual heat removal (RHR) Pump - No Green Indicating Light; June 10, 2003
SP 2089A; Train A RHR Pump and Suction Valve from the RWST Quarterly Test, Revision 4
AR CAP 030769; Unplanned LCO [Limiting Condition for Operation] Not Met Due to 21 RHR Out of Service; June 10, 2003
AR CAP 024073; Develop Maintenance for the Aux Contacts for 4-kv Switchgear; July 5, 2002

AR CAP 031333; Failure of Indicating Lither Circuit for Breaker 25-7 21 RHR Pump; July 11, 2003
OE 023147; Assess NRC Information Notice 2002-34; November 27,2002
ACE 008727; Unplanned LCO Not Met Due to 21 RHR Out of Service, June 11, 2003
PE 0007; 5HK250/350 Breaker Testing Maintenance & Repair - Minor; Revision 2
PE 0008; 5HK250/350 Breaker Testing Maintenance & Repair - Major; Revision 2
PE 0009; 4kv Switchgear Preventative Maintenance; Revision 11
RHR Maintenance Rule Status and Supporting Information; September 5, 2003
NE-116785; Sheet 19; 21 Residual Heat Removal Pump Bus 25 Cubicle 7; Revision A

1R13 Maintenance Risk Assessments and Emergent Work Control

Cooling Water Supply Piping for D2
AR CAP 031134; Pinhole Leak Discovered in Line 6-CL-30 Cooling Water Supply to D2; June 30, 2003
Operations Log Entries; July 1 & 2, 2003

Unit 2 Volume Control Tank Level Instrument
Unit 2 Configuration Risk Assessment; July 2, 2003
Operations Log Entries; July 2 & 3, 2003
Operating Information No. 03-105; 2LT-141 (Volume Control Tank Level Transmitter); July 2, 2003
WO 0304441; Unit 2 Volume Control Tank Level Indications Diverging; July 2, 2003;
PINGP Procedure H24.1; Assessment and Management of Risk Associated with Maintenance Activities; Revision 6

Unit 2 Emergency Core Cooling System, Train 1
Unit 2 Configuration Risk Assessment; July 7, 2003
High Level Summary Schedule, Work Week 3305A; July 7, 2003

1R14 Nonroutine Evolutions

Operator Response to Boron Addition Event While Restoring Letdown
Operating Procedure 1C12.1; Letdown, Charging, and Seal Water Injection-Unit 1; Revision 1
Abnormal Operating Procedure 2C12.1 AOP1; Loss of Reactor Coolant Pump Seal Injection; Revision 0
AR CAP 031647; Boron Released from 11 Mixed Bed; August 31, 2003
ACE 008756; Apparent Cause Evaluation for Boron Release From 11 Mixed Bed; August 31, 2003
CE 003246; Boron Released from 11 Mixed Bed; August 31, 2003

Operator Response to a Loss of CT-12
Operating Procedure C20.2; Substation System; Revision 8
Operating Procedure C20.3; Electrical Power System Security Analysis; Revision 9
Abnormal Operating Procedure C20.3 AOP 1; Evaluating System Operating Conditions When Security Analysis is Out-of-Service; Revision 4
Abnormal Operating Procedure C20.3 AOP7; Electric Power System Operating Restrictions and Limitations Loss of 10 Transformer; Revision 5

Abnormal Operating Procedure C20.3 AOP 9; Electric Power System Operating Restrictions and Limitations Loss of CT-12 Transformer; Revision 6
Operator Log Entries for July 26, 2003
AR CAP 031568; Momentary Loss of Power to Bus 26 Due to Loss of CT-12 Transformer; July 27, 2003
AR CAP 031573; Operating Committee Meeting on Course of Action for Restoration of 4 KV Bus CT-12 from CT-11; July 27, 2003

Unit 2 Reactor Cavity Draindown and Reduced Inventory Operations
Special Operating Procedure 2D2; RCS Reduced Inventory Operation; Revision 16
Unit 2 Shutdown Safety Assessment for September 17, 2003
Operating Procedure 2C4.1; RCS Inventory Control - Pre-Refueling; Revision 15

PI&R Review
Operating Procedure 2C1.3; Unit 2 Shutdown; Revision 50
AR CAP 032437; Unable to Restore Condenser Vacuum After Turbine Tripped due to Low Vacuum; September 13, 2003
AR CAP 032466; Unit 2 Turbine Trip During Shut Down due to Low Condenser Vacuum; September 14, 2003

1R15 Operability Evaluations

Maximum Containment Temperature for Operability
AR OPR 000416; Determine Maximum Containment Temperature for Operability of Containment; May 28, 2003
Operations Log Entries; June 24 & 25, 2003
AR CAP 031042; Unplanned LCO [Limiting Condition for Operation] Condition Entry Due to Containment Temperature Increase Greater Than 120 Degrees F; June 25, 2003
TS Bases B3.6.5; Containment Cooling System; Amendment No. 158

Containment Integrity, Charging Pump Suction Valves
AR OPR 000328; Containment Integrity, Charging Pump Suction Valves, SP-1366 (2366); August 14, 2002
AR CAP 031335; Containment Boundary Control for Unit 2 VC Charging Line, Containment Penetration 12; July 13, 2003
AR CAP 024655; Containment Integrity, Charging Pump Suction Valves, SP-1366 (2366); August 14, 2002
TS 3.6.3; Containment Isolation Valves; Amendment No. 158
USAR 5.2.2.1; Primary Containment Auxiliary Systems; Revision 25
Operating Procedure 2C19.1; Containment Unit 2; Revision 15

Operability of Transformer CT-12 with Leaking Potheads on Phase A and C
AR CAP 031671; Energize CT-12 After Repairs to A and C Phase Potheads Completed; July 31, 2003
OPR 000432; Energize CT-12 After Repairs to A and C Phase Potheads Completed; July 31, 2003
Operating Procedure C20.2; Substation System; Revision 8
Operating Procedure C20.3; Electrical Power System Security Analysis; Revision 9

Condition Evaluation for Number 12 Auxiliary Feedwater Pump with Suction Pressure Switch Found of Acceptance Criteria

AR CAP 031586; Evaluate 12 AFWP [Auxiliary Feedwater Pump] Suction PS 17776 As-found Data Greater That as Found Tolerance;
CE 003212; Evaluate 12 AFWP Suction PS 17776 As-found Data Greater That as Found Tolerance;
ENG-ME-293; Safety Related Tank Evaluation, Revision 2
ENG-ME-551; Water Available to AFWP with Out of Tolerance Suction Pressure Switch Setpoint; Revision 0

Operability Evaluation Reviews With Unresolved Issues
Design Basis Document DBD STR-02; Design Basis Document for the Auxiliary Building; Revision 2
Design Basis Document DBD STR-03; Design Basis Document for the Turbine Building; Revision 2
Pioneer Service and Engineering Company Structural Calculation Book 9
Stevens and Associates Calculation 02Q0357-C-001; Assessment of Old Service Building for Seismic and Tornado Loads
USAR Section 12.2.1.4.3.6
AR CAP 031668; Obstruction Block Auxiliary and Turbine Building Blowout Panels, July 31, 2003
OPR 000433; Obstruction Block Auxiliary and Turbine Building Blowout Panels, July 31, 2003
AR CAP 031775; Portions of Auxiliary and Turbine Buildings Designed for Less Than Required wind Loads, August 7, 2003
OPR 000434; Portions of Auxiliary and Turbine Buildings Designed for Less Than Required wind Loads, August 7, 2003
Operable But Degraded (OBD) 000064; Portions of Auxiliary and Turbine Buildings Designed for Less Than Required wind Loads, August 11, 2003

1R16 OWAs

AR CAP 031177; Potential Operator Workaround; July 2, 2003
AR OTH 006089; Potential Operator Workaround; July 2, 2003
Prairie Island Operator Work Around; July 23, 2003
Procedure 5AWI 3.10.8; Equipment Problem Resolution Process; Revision 3

1R17 Permanent Plant Modifications

10 CFR 50.59 Screening 1839; Change of Maximum Design Steam Generator Steam Flow
Calculation SPCRP015; Unit 1 Steam Generator Low-Low Reactor Water Level Reactor Trip; Revision 3
Calculation SPCRP015; Unit 1 Steam Generator Low-Low Reactor Water Level Reactor Trip; Revision 2
AR CAP 030876; At 100 percent Reactor Power the Steam Flow in 11 Steam Generator Exceeds 104 percent of Design, June 16, 2003

CE 002922; At 100 percent Reactor Power the Steam Flow in 11 Steam Generator Exceeds 104 percent of Design, June 17, 2003
CE 002923; At 100 percent Reactor Power the Steam Flow in 11 Steam Generator Exceeds 104 percent of Design, June 17, 2003
CA 005892; At 100 percent Reactor Power the Steam Flow in 11 Steam Generator Exceeds 104 percent of Design, June 17, 2003

1R19 Post-Maintenance Testing

21 SBVS
SP 2073A; Monthly Train A Shield Building Ventilation System Test; Revision 2
WO 0304927; Improper Indication on 21 SB Vent Filter Heater; July 7, 2003
AR CAP 031275; Undocumented Temperature Switch Installed in 21 Shield Building Vent Heater Circuit; July 9, 2003

11 Steam Generator Power Operated Relief Valve (PORV)
SP 1111A; Train A Monthly Main Steam Power Operated Relief Valve Test; Revision 5
WO 0304966; Repair 11 Steam Generator PORV, CV-31084 I/P Converter
AR CAP 031290; 11 Steam Generator PORV CV 31084 Indicates Increasing Temperature Downstream; July 10, 2003

1R20 Refueling and Other Outage Activities

Operating Procedure 2C1.4; Unit 2 Power Operations; Revision 31
Operating Procedure 2C1.3; Unit 2 Shutdown; Revision 50
Operating Procedure 2C15; Residual Heat Removal System Unit 2; Revision 28
Operating Procedure 2C28.1;Auxiliary Feedwater System Unit 2; Revision 11
Operating Procedure C19.9; Containment Boundary Control During Mode 5, Cold Shutdown and Mode 6, Refueling; Revision 10
Administrative Work Instruction 5AWI 15.6.1; Shutdown Safety Assessment; Revision 1
Prairie Island Nuclear Generating Plant (PINGP) Form 1103; Unit 2 Shutdown Safety Assessment; Revision 19
Maintenance Procedure D5.1; Spent Fuel Pit Fuel Handling Operations; Revision 32
Maintenance Procedure D5.2; Reactor Refueling Operations; Revision 38
Maintenance Procedure D58.2.9; Unit 2 Reactor Vessel Head Removal; Revision 8
Special Operations Procedure D5.2; Reactor Refueling Operations; Revision 38
AR CAP 032505; Containment Evacuation due to Low O2; September 14, 2003
AR CAP 032596; Unit 2 Polar Crane Temporary Hoist Failure; September 16, 2003
AR CAP 032899; Fuel Handling Transfer Cart Cable Weight System had Periodic Overloads at Start of Offload; September 23, 2003

1R22 Surveillance Testing

D1 Diesel Generator 18 Month 24 Hour Load Test
SP 1334; D1 Diesel Generator 18 Month 24 Hour Load Test; Revision 7
Prairie Island Technical Specification 3.8.1
Design Basis Document DBD SYS-38A; Emergency Diesel Generator System
AR CAP 033126; Abnormal Injection Flow Observed During SP 2092A; September 30, 2003

SP 1074A; Train A Auxiliary Building Special Vent System Quarterly Test; Revision 2
SP 1081.1; 121 Aux Building Special Ventilation Filter Removal Efficiency Test; Revision 11
Operations Log Entries for July 28, August 21, and September 4, 2003
Daily Work Schedules for July 28, August 21, and September 4, 2003
Prairie Island Technical Specification 5.5.9; Ventilation Filter Testing Program
Procedure H39; Ventilation Filter Testing Program; Revision 0
Maintenance Procedure D86; Protection of Pre, Absolute, and Charcoal Ventilation Filters from Contamination; Revision 5
Proceedings from the 19th DOE/NRC Nuclear Air Cleaning Conference, May 1987, Controversial Issues with Air Cleaning at Nuclear Power Stations, Presenter Dr. Ronald R. Bellamy
AR CAP 032104; Acceptability of Running Auxiliary Building Special Ventilation System while Painting in the Auxiliary Building; August 28, 2003 (NRC Identified)
CE 003453; Acceptability of Running Auxiliary Building Special Ventilation System while Painting in the Auxiliary Building; August 29, 2003
AR CAP 032408; Inadequate Guidance for Controlling Level of Painting in the Auxiliary Building

Integrated Safety Injection Test with Simulated Loss of Offsite Power
SP 2083; Unit 2 Integrated Safety Injection Test with Simulated Loss of Offsite Power; Revision 26
AR CAP 032514; Safeguards Logic In Test Annunciator Did Not Reset; September 15, 2003
AR CAP 032517; D5/D6 Voltage Regulator Rectifier Failure Alarms Received During Safety Injection Test Recovery; September 15, 2003
AR CAP 032540; Unit 2 Integrated Safety Injection Test Issues; September 16, 2003

Safety Injection Check Valve Testing
SP 2092A; Safety Injection Check Valve Testing (Head Off) Part A: High Head Safety Injection Flow Path Verification; Revision 25
SP 2092B; Safety Injection Check Valve Testing (Head Off) Part B: Refuel Water Storage Tank to Residual Heat Removal Flow Path Verification; Revision13
SP 2092C; Safety Injection Check Valve Testing (Head Off) Part C: Accumulator Flow Path Verification; Revision 11

Local Leak Rate Test
SP 2072.5; Local Leakage Rate Test of Penetration 5 (Reactor Coolant Drain Tank Pump Discharge; Revision 18

1R23 Temporary Modifications

10 CFR 50.59 Safety Screening 1845; Revision 0
Temporary Modification Package 03T162
WO 0304227; Installation of Temporary Modification on the 11 Containment Chiller
WO 0304230; Removal of Temporary Modification on the 11 Containment Chiller
USAR Section 10.4.1.2.1;Auxiliary Building and Containment Chilled Water System

2OS1 Access Controls for Radiologically Significant Areas

2003 Prairie Island RP Focused Self-Assessment Plan; Revision 0
PINGP 1352; Revision 1; Focused Self Assessment Checklist, Contamination Control
PINGP 1353, Revision 0; Focused Self-Assessment Data Collection Form, Contamination Control

Prairie Island Nuclear Generating Plant, Focused Self Assessment, Radioactive Material Control
PINGP 1351; Focused Self Assessment Plan, Control of Radioactive Material; Revision 0
CAP032595; Inadequate Change Management for Access into U-2 Personnel Airlock; dated September 16, 2003
CA006451; Pre-Job Briefing Held Without Required Information or All Required Personnel; dated August 5, 2003
CAP032500; Deficient RP Practices at Personnel Air Lock; dated September 14, 2003
CAP031666; Discrepancy in Rad Worker Practices and Expectations for SP 1090B; dated July 31, 2003
CAP032500; Deficient RP Practices at Personnel Air Lock; dated September 14, 2003

2OS2 As Low As Is Reasonably Achievable Planning And Controls

ALARA Review; 2003 ALARA Review for In Service Inspection and Associated Work
ALARA Review; 2003 ALARA Review for RCP Seal Removal, Inspection and Replacement
ALARA Review; 2003 ALARA Review for SG Primary Manway Bolt Hole Inspection
ALARA Review; 2003 ALARA Review for SG Primary Manway Remove and Install and Insert Remove and Install
ALARA Review; 2003 ALARA Review for SG Primary ECT of Tubes, Plug Install and Remove and Re-Rolling
ALARA Review; 2003 ALARA Review for SG Primary Nozzle Dam Install and Remove and SG Closeout Inspection
ALARA Review; RX Head Lift Preps and Associated Work
ALARA Review; RX Head Reassembly and Associated Work
Radiation Work Permit RWP 2142; Revision 1; Inspect Under Vessel Penetrations for Signs of Leakage; dated September 12, 2003
CAP031911; On Line Dose Goal for the Year is in Jeopardy; dated August 18, 2003
CAP032595; Inadequate Change Management for Access into U-2 Personnel Airlock; dated September 16, 2003
NMC Nuclear Oversight 2nd Quarter 2003 Assessment Report for Prairie Island; Assessment Number 2003-002-6
NMC Nuclear Oversight Observation Report 2003-002-6-006
NMC Nuclear Oversight Observation Report 2003-003-6-009
NMC Nuclear Oversight Observation Report 2003-003-6-014

4OA1 Performance Indicator Verification

Prairie Island Nuclear Generating Plant Form 1318A; Performance Indicators - Initiating Events; Revision 0; Unit 1 and Unit 2; 3rd and 4th Quarters 2002 and 1st and 2nd Quarters 2003
Section Work Instructions SWI O-53; Operations Performance Indicator Reporting; Revision 0; Unit 1 and Unit 2; 3rd and 4th Quarters 2002 and 1st and 2nd Quarters 2003
Prairie Island Unit 1 and Unit 2 Monthly Operating Reports; July 2002 through June 2003
Operating Logs; Unit 1 and Unit 2; 3rd and 4th Quarters 2002 and 1st and 2nd Quarters 2003
Plant Procedure H33.1; Performance Indicator Reporting Instructions; Revision 5
Plant Procedure H33; Performance Indicator Reporting; Revision 5
Prairie Island Nuclear Generating Plant Form 1318D; Performance Indicators - Reactor Coolant Activity; Revision 1; Unit 1 and Unit 2; 3rd and 4th Quarters 2002 and 1st and 2nd Quarters 2003
TS 3.4.17; RCS Specific Activity
Prairie Island Radiochemistry Data Sheets; July 2002 through June 2003
Prairie Island Nuclear Generating Plant Form 1318C; Performance Indicators - Safety System Functional Failures; Unit 1 and Unit 2; 3rd and 4th Quarters 2002 and 1st and 2nd Quarters 2003
Licensee Event Reports 50-282/02-02-00, 50-282/306/02-01-00, 50-282/306/03-02-00, 50-282/03-01-00, and 50-306/03-01-00
AR CAP 031239; Containment Control as a Locked High Radiation Area May Not Be Adequate to Prevent Inadvertent Entry

4OA2 Identification and Resolution of Problems

AR CAP 031275; Undocumented Temperature Switch Installed in 21 Shield Building Ventilation Heater Circuit; July 09, 2003
CA 006169; Undocumented Temperature Switch Installed in 21 Shield Building Ventilation Heater Circuit; July 11, 2003
ACE 008741; Undocumented Temperature Switch Installed in 21 Shield Building Ventilation Heater Circuit; July 11, 2003
EWR 006466; Undocumented Temperature Switch Installed in 21 Shield Building Ventilation Heater Circuit; August 7, 2003
AR CAP 032415; Inappropriate Priority for Work Orders For Extent of Condition Determination; September 12, 2003 (NRC Identified)
Administrative Work Instruction 5AWI 16.0.0; Action Request Process; Revision 4
Performance Assessment Fleet Procedure FP-PA-ARP-01, Action Request Process; Revision 1
Administrative Work Instruction 5AWI 15.0.2, Work Order Codes; Revision 9
Prairie Island Apparent Cause Evaluation Desktop Guide, Dated July 2003
WO 0306276; 11 Shield Building Special Ventilation System Determine Heater Cutout Switch Configuration
WO 0306277; 12 Shield Building Special Ventilation System Determine Heater Cutout Switch Configuration
WO 0306279; 22 Shield Building Special Ventilation System Determine Heater Cutout Switch Configuration
WO 0306280; 121 ABSVS Determine Heater Cutout Switch Configuration
WO 0306281; 122 ABSVS Determine Heater Cutout Switch Configuration

4OA5 Other Activities

TI 2515/152

WO 0300435; Perform Bare Metal Visual on Bottom of Rx Vessel; January 28, 2003
Section Work Instruction GSE-23; Engineering Department Personnel Certification Program; Revision 5
NMC Letter L-PI-03-084; Nuclear Regulatory Commission Bulletin 2003-02: Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity - 30-Day Response; September 19, 2003
AR CAP 032658; Evaluate Indications Found During Rx Vessel Bottom Head Inspection for Relevance; September 18, 2003
SP 1403 [2403]; Reactor Vessel Closure Head Bare Metal Visual Examination; dated August 13, 2003
SP 1407 [2407]; Leakage Examination of Canopy Seals; Mechanical Joints; And Other Pressure Retaining Components on the Reactor Vessel Head; dated August 13, 2003
CAP 033003; 2R22 RV Closure Head Bare Metal Visual Exam Results

LIST OF ACRONYMS USED

2R22	Unit 2 Refueling Outage Number 22
ABSVS	Auxiliary Building Special Ventilation System
ADAMS	Agencywide Documents Access and Management System
AFWP	Auxiliary Feedwater Pump
ALARA	As-Low-As-Is-Reasonably-Achievable
ANSI/ANS	American National Standard Institute/American Nuclear Society
AR	Action Request
ASME	American Society of Mechanical Engineers
AWI	Administrative Work Instruction
BATP	Boric Acid Transfer Pump
CA	Corrective Action
CAP	Corrective Action Program
CEDE	Committed Effective Dose Equivalent
CFR	Code of Federal Regulations
CR	Condition Report
DC	Direct Current
DOE	Department of Energy
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
ECT	Eddy Current Examination
ED	Electronic Dosimeter
EDY	Effective Degradation Years
EPRI	Electric Power Research Institute
EWR	Engineering Work Request
HEPA	High Efficiency Particulate Air
HRA	High Radiation Area
I/P	current-to-pneumatic
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
ISI	Inservice Inspection
JPM	Job Performance Measure
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LHP	Lower Head Penetrations
LHRA	Locked High Radiation Area
LORT	Licensed Operator Requalification Training
NCV	Non-Cited Violation
NFPA	National Fire Protection Association
NMC	Nuclear Management Corporation, LLC
NRC	U.S. Nuclear Regulatory Commission
OBD	Operable But Degraded
OPR	Operability Recommendation
OWA	Operator Workaround
PARS	Publicly Available Records
PI	Performance Indicators

PINGP	Prairie Island Nuclear Generating Plant
PORV	Power Operated Relief Valve
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RCE	Root Cause Evaluation
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RPM	Radiation Protection Manager
RPV	Reactor Pressure Vessel
RWP	Radiation Work Permit
SBVS	Shield Building Ventilation System
SDP	Significance Determination Process
SP	Surveillance Procedure
TI	Temporary Instruction
TP	Test Procedure
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report
VHP	Vessel Head Penetration
VHRA	Very High Radiation Area
VT	Visual Testing
WO	Work Order