UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

February 12, 2010

EA-10-009

Mr. Dennis R. Madison
Vice President
Southern Nuclear Operating Company, Inc.
Edwin I. Hatch Nuclear Plant
11028 Hatch Parkway North
Baxley, GA 31513

SUBJECT: EDWIN I. HATCH NUCLEAR PLANT, NRC INTEGRATED INSPECTION REPORT 05000321/2009005 AND 05000366/2009005 AND A PRELIMINARY GREATER THAN GREEN FINDING

Dear Mr. Madison:

On December 31, 2009, the Nuclear Regulatory Commission (NRC) completed an inspection at Edwin I. Hatch Nuclear Plant, Units 1 and 2. The enclosed integrated inspection report documents the inspection results, which were discussed on February 10, 2010, with you and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. Based on the results of this inspection, two findings involving the failure to establish and perform preventive maintenance activities to replace aged electrolytic capacitors were identified. One finding involving capacitors was identified with two examples on Unit 2 and one finding was identified on Unit 1. All examples of these findings represented a common performance deficiency. For Unit 2, the performance deficiency led to failures of the emergency diesel generator (EDG) loss of offsite power (LOSP) circuits and a failure of the power supply for the main feedwater median level controller. The 2A EDG LOSP timer card failure was discovered on February 12, 2009, during performance of a technical specification surveillance. The main feedwater median level controller power supply failure occurred on June 23, 2009, and resulted in a reactor scram.

The examples for Unit 2 were assessed, based on the best available information, including influential assumptions, using the applicable Significance Determination Process (SDP) and the finding was preliminarily determined to be a Greater Than Green Finding. Enclosed is a copy of the SDP Phase 3 analysis. It reflects a finding of greater than very low safety significance. Because there was a condition that existed for a finite exposure time and a plant event (reactor scram) was impacted by the finding, the risk from both was aggregated. The dominant factor for the 2A EDG LOSP timer card risk was the long exposure time. The dominant sequences for the EDG timer card deficiency involve events resulting in Loss of Offsite Power (LOSP).

In the event of a LOSP, the 2A Plant Service Water Pump would not be available for EDG cooling, which results in an increased likelihood of a Station Blackout (SBO). This increase in risk also exists for certain fires that could induce a LOSP. The risk from the turbine trip was dominated by sequences where the plant failed to scram.

As part of the SDP Phase 3 analysis, the increase in Large Early Release Frequency (LERF) was also estimated. The significance of the finding is influenced by large uncertainties in the calculation made for the LERF estimates. Because of these uncertainties, the result was classified as Greater Than Green.

The Unit 2 EDG LOSP timer card finding is also an Apparent Violation (AV) of technical specifications (T.S.) 5.4, Procedures, for failure to establish and perform preventive maintenance activities to replace electrolytic capacitors prior to their failure and is being considered for escalated enforcement in accordance with the Enforcement Policy. In addition, this finding has a cross-cutting aspect in the Operating Experience component of the Problem Identification and Resolution area [P.2(b)], because you did not effectively incorporate pertinent industry operating experience into the preventative maintenance program. Accordingly, Unresolved Item (URI) 05000321, 366/2009002-04, Failure of Unit 2 EDG LOSP Timer Cards, is closed. The current Enforcement Policy is included on the NRC's website at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html.

In addition to the capacitor issues for Unit 2, the previously identified performance deficiency also led to a failure of the Unit 1 Steam Jet Air Ejector condenser cooling water control valve differential pressure controller power supply, resulting in the November 22, 2008, reactor scram as described in LER 2008-004. Our review of this Unit 1 scram, including the risk analysis, is addressed in section 4OA3.2 of this report. The risk for this event was not aggregated into the Unit 2 finding as it only affected Unit 1.

These findings do not represent a current safety concern because all of the Unit 2 EDG LOSP timer cards, their associated power supplies, the power supply for the Unit 2 main feedwater median level controller, 2C32-K648, as well as the Unit 1 controller power supply for the condensate valve have been replaced.

In accordance with Inspection Manual Chapter (IMC) 0609, we intend to complete our evaluation using the best available information and issue our final determination of safety significance within 90 days of the date of this letter. The SDP encourages an open dialogue between the staff and the licensee; however, the dialogue should not impact the timeliness of the staff's final determination. Before we make a final decision on this matter, we are providing you an opportunity to: (1) present to the NRC your perspectives on the facts and assumptions used by the NRC to arrive at the finding and its significance at a Regulatory Conference or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within approximately 30 days of the receipt of this letter and we encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. The NRC will also issue a press release to announce the conference. If you decide to submit only a written response, such a submittal should be sent to the NRC within 30 days of the receipt of this letter.

Please contact Mr. Scott M. Shaeffer at (404) 562-4521 within 10 business days of the date of your receipt of this letter to notify the NRC of your intentions. If we have not heard from you within 10 business days, we will continue with our significance determination and enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violation may change as a result of further NRC review.

The report also documents three NRC-identified findings and one self-revealing finding of very low safety significance (Green). Three of these findings were determined to involve violations of NRC requirements. Additionally, two licensee-identified violations which were determined to be of very low safety significance are listed in this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest any of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Hatch Nuclear Plant. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region II, and the NRC Resident Inspector at the Hatch Nuclear Plant. The information you provide will be considered in accordance with the Inspection Manual Chapter (IMC) 0305.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and enclosure 1 will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html.

Sincerely,
/RA/

Leonard D. Wert, Jr., Director
Division of Reactor Projects

Docket Nos.: 50-321, 50-366
License Nos.: DPR-57 and NPF-5

Enclosures: 1. Inspection Report 05000321/2009005, 05000366/2009005
w/Attachment: Supplemental Information
2. SDP Phase 3 Analysis (official use only-proprietary information)

cc w/o encl 2: (See page 4)

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Sincerely,
/RA/

Leonard D. Wert, Jr., Director
Division of Reactor Projects

Docket Nos.: 50-321, 50-366
License Nos.: DPR-57 and NPF-5

Enclosures: 1. Inspection Report 05000321/2009005, 05000366/2009005
w/Attachment: Supplemental Information
2. SDP Phase 3 Analysis (official use only-proprietary information)

cc w/o encl 2: (See page 4)

X PUBLICLY AVAILABLE ☐ NON-PUBLICLY AVAILABLE ☐ SENSITIVE X NON-SENSITIVE

ADAMS: ☐ Yes ACCESSION NUMBER:________________________ ☐ SUNSI REVIEW COMPLETE

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SIGNATURE	Via email	Via email	Via email	Via email	Via email	GTM /RA/	SMS /RA for/
NAME	EMorris	PNiebaum	BCaballero	DJones	JEargle	GMcDonald	Tlighty
DATE	02/11/2010	02/12/2010	02/10/2010	02/10/2010	02/11/2010	02/11/2010	02/12/2010
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SIGNATURE	SMS /RA/	SES /RA for/	JTM /RA/				
NAME	SShaeffer	CEvans	JMunday				
DATE	02/12/2010	02/11/2010	02/12/2010				
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: G:\DRPII\RPB2\HATCH\REPORTS\2009 IRS\09-05\HATCH 2009-005 W-O-SDP.DOC cc w/o encl 2:

Managing Attorney and Compliance Officer
Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

B. D. McKinney, Jr.
Regulatory Response Manager
Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

Jeffrey T. Gasser
Executive Vice President
Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

N. J. Stringfellow
Licensing Manager
Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

T. D. Honeycutt
Regulatory Response Supervisor
Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

L. Mike Stinson
Vice President
Fleet Operations Support
Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

Paula Marino
Vice President
Engineering
Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

Moanica Caston
Vice President and General Counsel
Southern Nuclear Operating Company, Inc.
Electronic Mail Distribution

Steven B. Tipps
Hatch Principal Engineer - Licensing
Edwin I. Hatch Nuclear Plant
Electronic Mail Distribution

Mr. Ken Rosanski
Resident Manager
Edwin I. Hatch
Oglethorpe Power Corporation
Electronic Mail Distribution

Chris Clark
Commissioner
Georgia Department of Natural Resources
Electronic Mail Distribution

Lee Foley
Manager of Contracts Generation
Oglethorpe Power Corporation
Electronic Mail Distribution

Arthur H. Domby, Esq.
Troutman Sanders
Electronic Mail Distribution

James C. Hardeman
Environmental Radiation Program Manager
Environmental Protection Division
Georgia Department of Natural Resources
Electronic Mail Distribution

Ted V. Jackson
Emergency Response and Radiation
Program Manager
Environmental Protection Division
Georgia Department of Natural Resources
Electronic Mail Distribution

F. Allen Barnes
Director
Environmental Protection Division
Georgia Department of Natural Resources
Electronic Mail Distribution

Cynthia A. Sanders
Radioactive Materials Program Manager
Environmental Protection Division
Georgia Department of Natural Resources
Electronic Mail Distribution

(cc w/o encl 2 continued next page)

cc w/o encl 2 cont.

James A. Sommerville
Program Coordination Branch Chief
Environmental Protection Division
Georgia Department of Natural Resources
Electronic Mail Distribution

Mr. Steven M. Jackson
Senior Engineer - Power Supply
Municipal Electric Authority of Georgia
Electronic Mail Distribution

Mr. Reece McAlister
Executive Secretary
Georgia Public Service Commission
Electronic Mail Distribution

Chairman
Appling County Commissioners
County Courthouse
69 Tippins Street, Suite 201
Baxley, GA 31513

Letter to Dennis R. Madison from Leonard D. Wert dated February 12, 2010

SUBJECT: EDWIN I. HATCH NUCLEAR PLANT, NRC INTEGRATED INSPECTION REPORT 05000321/2009005 AND 05000366/2009005 AND A PRELIMINARY GREATER THAN GREEN FINDING

Distribution w/encl:
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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-321, 50-366
License Nos.:	DPR-57 and NPF-5
Report Nos.:	05000321/2009005 and 05000366/2009005
Licensee:	Southern Nuclear Operating Company, Inc.
Facility:	Edwin I. Hatch Nuclear Plant
Location:	Baxley, Georgia 31513
Dates:	October 1 – December 31, 2009
Inspectors:	E. Morris, Senior Resident Inspector P. Niebaum, Resident Inspector B. Caballero, Operations Engineer (1R11.2) D. Jones, Senior Reactor Inspector (4OA5) J. Eargle, Reactor Inspector (4OA5) G. Macdonald, Sr. Reactor Analyst (4OA5)
Approved by:	Scott M. Shaeffer, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure 1

SUMMARY OF FINDINGS

IR 05000321/2009-005, 05000366/2009-005; 10/01/2009-12/31/2009; Edwin I. Hatch Nuclear Plant, Units 1 and 2; Maintenance Effectiveness, Event Follow-up, and Other Activities.

The report covered a three-month period of inspection by one senior resident inspector, one resident inspector, one operations engineer, one senior reactor inspector, one reactor inspector, and one senior reactor analyst. Four Green findings, three of which were NCVs, and one AV with two examples with potential safety significance greater than Green, were 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). The cross-cutting aspects were determined using IMC 0305, Operating Reactor Assessment Program. Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- TBD A self-revealing apparent violation (AV) of TS 5.4, Procedures, was identified for failure to establish and perform preventive maintenance activities to replace electrolytic capacitors prior to their failure, specifically the electrolytic capacitors for the Unit 2 EDG LOCA/LOSP timer cards and their associated power supplies. As a result, between 2005 and 2009, the 2A, 2C and the 1B swing EDG experienced failures of the LOSP/LOCA circuitry, which were attributed to electrolytic capacitor age-related failures. On February 12, 2009 the Unit 2A EDG LOSP timer card was found in a failed state. These issues were documented in the licensee's corrective action program as condition reports (CRs) 2005103415, 2008107899, 2008107935, 2009101237 and 2009102221. All Unit 2 EDG LOCA/LOSP time cards were replaced and their power supplies refurbished with new capacitors.

  A second example of this performance deficiency was also identified. The performance deficiency directly contributed to the feedwater level controller 2C32-K648 power supply failing resulting in a Unit 2 automatic scram on June 23, 2009 (LER 05000366/2009-004). The licensee replaced the failed power supply. This issue is documented in the licensee's corrective action program as CR 2009106352.

  This finding with two examples is more than minor because if left uncorrected, the performance deficiency has the potential to lead to a more significant safety concern. Specifically, equipment containing electrolytic capacitors could fail and result in a plant transient or render systems/components used to respond to a plant transient unreliable or unavailable. The inspectors evaluated the finding in accordance with IMC 0609, Significance Determination Process, Attachment 4, Phase 1 – Initial Screening. It was determined that a SDP Phase 2 analysis was required since the first example of the finding represents an actual loss of a safety function of a single train (EDG) for greater than its TS allowed outage time. The SDP Phase 2 analysis evaluated the finding for a Loss of Offsite Power (LOSP) event and required a Phase 3 review. The risk associated with the example for the failed main feedwater median level 2C32-K648 controller power supply was aggregated into the result of the phase

3 for the Unit 2 EDG timer cards. This finding has potential safety significance greater than very low safety significance (Green) and is classified as an apparent violation. The finding was also determined to have a cross-cutting aspect in the Operating Experience component of the Problem Identification and Resolution area (P.2(b), because the licensee did not effectively incorporate pertinent industry operating experience into the preventative maintenance program for the Unit 2 EDG LOCA/LOSP and the feedwater level controller components. (Section 1R12.2)

- Green. The NRC identified a Green non-cited violation of 10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, for the failure to scope the monitoring of the Unit 1 and Unit 2 Reactor Building Equipment Drain Sump (RBEDS) system into the licensee's maintenance rule program. The licensee initiated Condition Report (CR) 2009105110 and 2009105111 to address this issue.

  The team determined that the licensee's failure to scope the RBEDS system into the maintenance rule program was a performance deficiency. This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to monitor and establish goals that would have addressed repetitive air operated valve (AOV) failures in the RBEDS system, resulted in a lack of assurance that the system would reliably perform its safety function during a design bases internal flooding event. This finding was assessed using the Phase 1 screening worksheet of the SDP and determined a Phase 3 analysis was required. Phase 3 results characterized the performance deficiency as very low safety significance (Green). A cross-cutting aspect was not identified because the finding does not represent current performance. (Section 4OA5.3.1)

- Green. The NRC identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control, for the failure to translate the design bases as stated in the FSAR into specifications for Units 1 and 2. Specifically, single failure design criteria for the reactor building sump level instrumentation has not been met since initial plant operation. The licensee initiated CRs (2009105744, 2009105110, 2009105111, 2009105615, and 2009105727) and administratively closed flood isolation valves as an interim compensatory measure.

  The team determined that the licensee's failure to install single failure proof level switches as stated in the UFSAR was a performance deficiency. This finding is more than minor because it is associated with the design control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, a failure of a level switch would adversely impact the automatic closure of flood isolation valves that protect safety-related equipment during a design bases internal flooding event. This finding was assessed using the Phase 1 screening worksheet of the SDP and determined a Phase 3 analysis was required. Phase 3 results characterized the performance deficiency as very low safety significance (Green) based on risk. A cross-cutting aspect was not identified because the finding does not represent current performance. (Section 4OA5.3.2)

- Green. The NRC identified a Green non-cited violation of 10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, for the licensee's failure to monitor the non-interruptible essential instrument air check valves in a manner sufficient to provide reasonable assurance that the components were capable of fulfilling their intended function. The licensee initiated CR 2009105109 and established compensatory measures to mitigate potential back leakage via the check valves during a loss of instrument air event.

  The team determined that the licensee's failure to perform periodic maintenance on non-interruptible essential instrument air header check valves was a performance deficiency. This finding is more than minor because it is similar to example 7.d. of Inspection Manual Chapter 0612, Appendix E, and because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to perform periodic maintenance or testing of the check valves resulted in a lack of reasonable assurance that the non-interruptible essential air system would provide sufficient capability to operate the hardened containment vent during a loss of instrument air event. The failure to operate the containment hardened vent could adversely affect the mitigation function of the decay heat removal system. This finding was assessed using the Phase 1 screening worksheet of the SDP and determined a Phase 3 analysis was required. Phase 3 results characterized the performance deficiency as very low safety significance (Green) based on risk. A cross-cutting aspect was not identified because the finding does not represent current performance. (Section 4OA5.4)

Cornerstone: Initiating Events

- Green. A self-revealing finding was identified for the licensee's failure to establish and perform preventive maintenance activities to replace electrolytic capacitors as required per licensee procedure, NMP-ES-006, Predictive Maintenance Implementation and Continuing Equipment Reliability Improvement. As a result, this failure directly resulted in a Unit 1 manual reactor scram on November 22, 2008 (LER 05000321/2008-004). The licensee replaced the steam jet air ejector inter-condenser cooling water control valve differential pressure controller (1N21-K088) failed power supply. This issue was documented in the licensee's corrective action program as CR 2008111605.

  This performance deficiency was more than minor because it is associated with the Equipment Performance attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during power operations, in that, on November 22, 2008 the 1N21-K088 power supply failed which led to a manual reactor scram for Unit 1. The significance of this finding was screened with NRC

Inspection Manual Chapter 0609 Attachment 4, and since it contributed to an increase in the likelihood of a reactor trip and affected the reliability and availability of mitigating system equipment, a phase 2 SDP analysis was required. The phase 2 review of the Hatch pre-solved worksheet did not have an appropriate column to evaluate the finding, therefore a phase 3 significance determination process (SDP) analysis was required. The phase 3 SDP analysis was performed by a regional senior risk analyst (SRA), as a loss of main feedwater initiating event assessment using the NRC's Standardized Plant Analysis Risk (SPAR) model. The result was <1E-6 for conditional core damage probability and <1E-7 for conditional large early release probability, a GREEN finding. The dominant sequences were Anticipated Transient Without Scram (ATWS) sequences. The analysis assumed condensate remained available throughout the transient, and that main feedwater was recovered with a human error probability determined using the NRC's SPAR H methodology. The large early release frequency (LERF) risk was determined using the ATWS LERF multiplier from the Hatch phase 2 notebook. The inspectors determined this finding has a cross-cutting aspect in the Operating Experience component of the Problem Identification and Resolution area, because the licensee did not implement and institutionalize operating experience through changes to station processes, procedures, equipment, and training programs, in that, the licensee did not make changes to station processes when internal and external operating experience indicated similar electrolytic capacitors failures were occurring. (P.2(b)). (Section 4OA3.2)

B. Licensee-Identified Violations

Violations of very low safety significance or severity level IV that were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 started the inspection period operating at or near full Rated Thermal Power (RTP). On October 2, the B reactor feed pump tripped which caused power to be reduced to 57%. Unit 1 returned to 100% power on October 14 and remained at or near full RTP until October 26, when planned main turbine testing required a power reduction to 65%. Unit 1 returned to 100% on October 28 and remained at or near full RTP until December 12, when a high bearing temperature alarm for A main circulating water pump was received and the unit power was reduced to 50%. Unit 1 returned to 100% on December 14 and remained at or near full RTP through the end of the inspection period.

Unit 2 started the inspection period operating at or near full RTP. On November 2 reactor power was reduced to 65% to perform reactor flux tilt testing. Unit 2 returned to 100% power on November 14 and remained at or near full RTP until November 26 when power was reduced to 65% to perform leak repair of the B reactor feed pump discharge piping. Unit 2 returned to 100% on November 24 and remained at or near full RTP through the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment

a. Inspection Scope

Partial Walkdowns. The inspectors performed partial walkdowns of the following three systems when the opposite train was removed from service, the remaining operable system/train with high risk significance for the plant configuration existed, or the system/train that was recently realigned following an extended system outage or the risk significant single train system existed. The inspectors checked system valve positions, electrical breaker positions, and operating switch positions to evaluate the operability of the opposite trains or components by comparing the position listed in the system operating procedure to the actual position. Documents reviewed are listed in the Attachment.

System Walked Down:

- Unit 1 A loop residual heat removal (RHR) while 1 B loop RHR was out of service on October 27, 2009
- Unit 1 A emergency diesel generator (EDG) while 1 C EDG was out of service on November 16, 2009
- Unit 2 A control rod drive pump while 2 B control rod drive pump was out of service on November 24, 2009

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

Fire Area Tours. The inspectors toured the following five risk significant plant areas to assess the material condition of the fire protection and detection equipment, verify fire protection equipment was not obstructed and that transient combustibles were properly controlled. The inspectors reviewed the Fire Hazards Analysis drawings H-11846 and H-11847 to verify that the necessary fire fighting equipment, such as fire extinguishers, hose stations, ladders, and communications equipment, was in place. Documents reviewed are listed in the Attachment.

- Unit 1/2 Control Building General Area 130' elevation
- Unit 1 Emergency Diesel Generator Rooms 1A, 1B, 1C
- Unit 1 4160 VAC Emergency Switchgear Rooms 1E, 1F, 1G
- Unit 2 Emergency Diesel Generator Rooms 2A, 2C
- Unit 2 4160 VAC Emergency Switchgear Rooms 2E, 2F, 2G

b. Findings

No findings of significance were identified.

1R06 Internal Flood Protection

1. Walkdown of Selected Areas

a. Inspection Scope

The inspectors reviewed selected risk-important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations and abnormal operating procedures for licensee commitments. The inspectors walked-down the area listed below to verify plant design features and plant procedures for flood mitigation were consistent with design requirements and internal flooding analysis assumptions. The inspectors reviewed flood protection barriers, which included plant floor drains, condition of room penetrations, condition of the sumps in the rooms, and condition of water-tight doors. The inspectors also reviewed CRs to verify the licensee was identifying and resolving problems in accordance with their corrective action program. Documents reviewed are listed in the Attachment.

- Unit 2 Reactor Building 130' and 158' elevations
- Unit 2 Reactor Building Southeast Diagonal

b. Findings

No findings of significance were identified.

2. Inspection of Underground Bunkers

a. Inspection Scope

The inspectors performed inspections of two below grade pull boxes (PB) that contain safety-related medium voltage (4160 VAC) cables. The inspectors also reviewed CRs to verify the licensee was identifying and resolving problems in accordance with their corrective action program. Documents reviewed are listed in the Attachment.

- PB1-BF containing safety-related 4160 VAC cable R22-S005-ES1-M08
- PB1-BB containing safety-related 4160 VAC cable R22-S005-ES1-M08

b. Findings

Introduction: An unresolved item (URI) was opened related to underground pull box inspections which revealed a safety-related 4160 volt cable located in two pull boxes was submerged under water. The determination of a performance deficiency cannot be made until further information is provided by the licensee to support that the cables are designed, qualified, and acceptable for operation in a wetted and/or submerged environment.

Description: On December 10, 2009 during inspection of underground bunkers subject to flooding, the inspectors identified that safety-related 4160 volt cable, R22-S005-ES1-M08, located in pull boxes PB1-BF and PB1-BB was submerged. This issue was captured in the licensee's corrective action program as CR 2009111808. The inspectors require documentation supporting the cables design, qualification, and testing history to evaluate whether this issue constitutes a performance deficiency. URI 05000321,366/2009005-01, "Submerged safety-related medium voltage cable" was identified to track this issue.

1R11 Licensed Operator Requalification

.1 Resident Quarterly Observation

a. Inspection Scope

The inspectors observed the performance of licensee simulator scenario LT-SG-50918-00, which included a condensate booster pump trip, condenser air in-leakage, loss of condenser vacuum, and anticipated transient without scram. The inspectors reviewed the proper classification in accordance with the Emergency Plan and licensee procedures 10AC-MGR-019-0, Procedure Use and Adherence, and DI-OPS-59-0896, Operations Management Expectations, to verify formality of communication, procedure usage, alarm response, control board manipulations, group dynamics, and supervisory oversight. The inspectors attended the post-exercise critique of operator performance to assess if the licensee identified performance issues were comparable to those identified by the inspectors. In addition, the inspectors reviewed the critique results from previous training sessions to assess performance improvement.

b. Findings

No findings of significance were identified.

.2 Annual Review of Licensee Requalification Examination Results IP 71111.11B

a. Inspection Scope

On September 7, 2009, the licensee completed administering the annual requalification operating tests and on December 31, 2009, the licensee completed administering the biennial written examinations which are required to be given to all licensed operators in accordance with 10 CFR 55.59(a) (2). The inspectors performed an in-office review of the overall pass/fail results of the written examination, individual operating tests, as well as the crew simulator operating tests. These results were compared to the thresholds established in Manual Chapter 609 Appendix I, Operator Requalification Human Performance Significance Determination Process.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

.1 Routine Maintenance Effectiveness Inspection

a. Inspection Scope

The inspectors reviewed the following four samples associated with structures, systems, and components to assess the licensee's implementation of the Maintenance Rule (10 CFR 50.65) with respect to the characterization of failures and the appropriateness of the associated (a) (1) or (a) (2) classification. The inspectors reviewed operator logs, associated CRs, Maintenance Work Orders (MWO), and the licensee's procedures for implementing the Maintenance Rule to determine if equipment failures were being identified, properly assessed, and corrective actions established to return the equipment to a satisfactory condition. Documents reviewed are listed in the Attachment.

- Vital DC batteries capacity margin low
- 1B EDG standby service water pump flow degradation
- 1C RHRSW pump bearing high temperature
- 2C EDG output breaker failed to close

b. Findings

The inspectors determined the circumstances involving the 2C EDG output breaker failing to close included a performance deficiency and a licensee-identified violation of 10 CFR 50 Appendix B, Criterion V. Refer to Section 4OA7 for the disposition of the issue.

.2 (Closed) URI 05000366/2009002-04 Failure of the Unit 2 EDG LOCA/LOSP Timer Cards/(Closed) LER 05000366/2009-004 Turbine Trip On High Reactor Water Level Due to Failed Circuit Board Results in Reactor Scram

a. Inspection Scope

The inspectors reviewed this URI, the licensee's root cause report and associated corrective actions. The inspectors identified a performance deficiency, in that, electrolytic capacitors for these components remained in service beyond the vendor recommended service life. This issue was captured in the licensee's corrective action program (CAP) as CR 2009102221. This URI and associated LER are closed.

b. Findings

Introduction: A self-revealing apparent violation (AV) of TS 5.4, Procedures, was identified for failure to establish and perform preventive maintenance activities to replace electrolytic capacitors prior to their failure, specifically related to the electrolytic capacitors for the Unit 2 EDG LOCA/LOSP timer cards and their associated power supplies. As a result, between 2005 and 2009 the Unit 2A, 2C and swing EDG 1B experienced failures of the LOSP/LOCA circuitry which were attributed to electrolytic capacitor age-related failures. This finding has potential safety significance greater than very low safety significance and is classified as an AV pending completion of the significance determination process (SDP).

Description:

2A EDG	1B EDG (swing)	2C EDG
2E bus	2F bus	2G bus
2A PSW pump	2C & 2D PSW pumps	2B PSW pump

The LOCA/LOSP timer cards function to properly sequence the applicable safety-related plant service water (PSW) pumps and other equipment onto the associated essential 4160VAC bus after that bus is re-energized from the EDG following a LOSP or a concurrent LOSP/LOCA event. The PSW system provides cooling water to the EDG's, the Emergency Core Cooling Systems (ECCS) room coolers, and the safety-related MCR Air Conditioning System.

The EDG timer cards were installed in 1988 under the site's design change process on Unit 2 only. The timer cards were installed for the Unit 2 essential 4160VAC busses 2E, 2F and 2G. The 2A EDG is the emergency power source for the 2E bus. The 1B EDG is the swing EDG and can provide power to the 2F bus. The 2C EDG is the emergency power source for the 2G bus. See table above for a reference.

Age-related failures of electrolytic capacitors have been documented in the industry previously. An Electric Power Research Institute (EPRI) document, TR-112175, Capacitor Application and Maintenance Guide, dated August 1999, states that capacitor change outs are performed between 7 and 15 years depending on vendor recommendations and plant operating experience. Another EPRI document, Power Supply Maintenance and Application Guide (1003096), dated December 2001, states that many of the power supplies that failed had been in service greater than 15 years on average. Additionally, the licensee was made aware of applicable operating experience related to electrolytic capacitors as documented in CR2005111157 dated November 17, 2005. This CR lists five examples of operating experience documents related to failed electrolytic capacitors. Furthermore, the qualification report for the EDG timer cards limited the life of the power supply electrolytic capacitors to 10 years. Licensee procedure, NMP-ES-006 Predictive Maintenance Implementation and Continuing Equipment Reliability Improvement, requires the licensee to incorporate vendor and pertinent industry operating experience information into their preventative maintenance program. Neither an evaluation that justified extending the service life of the EDG LOCA/LOSP timer card and power supply capacitors beyond 10 years, nor preventive maintenance to replace electrolytic capacitors was performed by the licensee.

On March 14, 2005, the 2C EDG LOCA/LOSP timer cards failed and caused intermittent alarms in the Main Control Room. The licensee determined that the power supply which feeds both of these timer cards was defective. According to maintenance work order 2050735903, the 125VDC power supply output contained a 10VAC ripple which was indicative of a failing filter circuit in the power supply. The licensee replaced the power supply, verified the DC output voltages were acceptable with no voltage ripple present and left the original timer cards installed. This power supply had been in service for approximately 17 years before it was replaced.

Between July 30 and July 31, 2008, the 1B EDG LOSP timer card experienced an input/output error on three occasions and annunciator DIESEL GEN B LOADING TIMER FAILURE was received in the Main Control Room (MCR) on each occasion. This issue was captured in the licensee’s corrective action program as CR2008107899 and CR 2008107935. The licensee staff responded to the annunciator in accordance with the annunciator response procedure and reset the LOSP timer card locally within approximately fifteen minutes of each annunciator. On August 1, 2008, Operations management declared the LOSP timer card inoperable due to its unreliability from the previous 24 hour period. The LOSP timer card was replaced on August 1, 2008, and a post maintenance test was performed satisfactorily. The timer card power supply had been in service for approximately 20 years and was not replaced at this time. The root cause team that would later investigate this issue in 2009, determined that excessive noise existed on the 125VDC and 24VDC power supply outputs. The noise on the 125VDC power supply output reached a peak amplitude of 185V. The noise on the 24VDC power supply output reached a peak amplitude of 38 volts. Electrolytic capacitors used in power supply circuits tend to exhibit increased noise toward the end of life.

On February 12, 2009, the 2A EDG LOSP timer card did not function as expected during the performance of the Logic System Functional Test (LSFT) per licensee procedure 42SV-R43-018-2. This procedure is used to satisfy a portion of TS surveillance requirement (SR) 3.8.1.6 required every 24 months. The LOSP timer card was found to have an input/output error, but did not result in a MCR annunciator, therefore the exact time of failure is indeterminate. The last time this component was known to be operable and available was after completion of the 24 month surveillance test on March 23, 2007. The licensee replaced the LOSP timer card and performed a post maintenance test successfully on February 13, 2009. The licensee developed a team to investigate the causes of the LOSP timer card input/output errors that have occurred to date. The team reached the conclusion that the timer cards were aged and that electrolytic capacitors installed on the timer cards were likely aged and should be replaced. On February 22, 2009, the licensee replaced the electrolytic capacitors on the LOCA and LOSP timer cards. The timer card power supply had been in service for approximately 20 years and was not replaced at this time. The root cause team that would later investigate this issue determined that an excessive voltage ripple existed on the 125VDC and 24VDC power supply outputs. The voltage ripple on the 125VDC power supply output had oscillations between +36 volts and -24 volts. The voltage ripple on the 24VDC power supply output had oscillations between +/- 5 volts. As noted on the 2C EDG power supply failure, excessive voltage ripple is indicative of a failing filter circuit in the power supply.

On March 1, 2009, CR2009102221 was written to document the Unit 2 EDG LOSP timer card failures. This CR was classified as severity level (SL) 1 requiring a root cause determination and was also used as the roll-up CR for the CRs discussed previously. The root cause team determined that the 1B and 2C LOCA and LOSP timer cards contained aged electrolytic capacitors and should be replaced. On March 8, 2009, the licensee installed refurbished timer cards with new electrolytic capacitors for the 2C EDG. On March 12, 2009, the licensee installed refurbished timer cards with new electrolytic capacitors for the 1B EDG. The root cause team determined the power supplies for the 2A and 1B EDG LOCA/LOSP timer cards contained electrolytic capacitors that had been in service longer than their qualified life of 10 years. On March 12, 2009, the licensee replaced the 2A EDG timer card power supply. On March 16, 2009, the licensee replaced the 1B EDG timer card power supply.

The following additional example of this performance deficiency was identified.

Introduction: The licensee failed to establish and perform preventive maintenance activities to replace aged electrolytic capacitors which was a performance deficiency. The performance deficiency directly attributed to the main feedwater median level controller 2C32-K648 power supply failing resulting in a Unit 2 automatic scram on June 23, 2009 (LER 05000366/2009-004).

Description: On June 23, 2009, an automatic reactor scram occurred on Unit 2 as a result of a turbine trip due to high reactor water level. The licensee determined the cause of the high reactor water level was failure of an electrolytic capacitor in the power supply for main feedwater median level controller 2C32-K648. This controller provides reactor water level indication and provides an input into the feedwater master controller 2C32-R600. With this controller failed, reactor water level increased until a fast closure of the turbine control valves occurred, causing a main turbine trip and reactor scram. A reactor scram is automatically initiated on a turbine control valve fast closure.

The cause of the reactor water level controller 2C32-K648 power supply failure was due to age-related degradation of electrolytic capacitor, C2. This controller had been in service for approximately 12 years. The licensee did not utilize their PM program as defined by licensee procedure NMP-ES-006, Preventative Maintenance Implementation and Continuing Equipment Reliability Improvement. This procedure states in part that the PM program will utilize industry experience to ensure the reliability of plant equipment. It further states that a PM basis review will include a review of operating experience and failure history for the component type. Contrary to this, the licensee failed to incorporate applicable industry OE into their PM process and replace the electrolytic capacitors in the 2C32-K648 controller power supply prior to its failure. This issue was captured in the licensee's corrective action program (CAP) as CR 2009106352.

<u>Analysis</u>: The inspectors concluded the licensee's failure to establish and perform preventive maintenance activities to replace aged electrolytic capacitors prior to their failure was a common performance deficiency applicable to both the above examples. Specifically, the Unit 2 EDG LOCA/LOSP timer cards and their associated power supplies and the Unit 2 controller 2C32-K648 power supply contained aged electrolytic capacitors resulting in multiple failures.

This finding with two examples is more than minor because if left uncorrected the performance deficiency could lead to a more significant safety concern. Specifically, equipment containing electrolytic capacitors could fail and result in a plant transient or render systems/components used to respond to a plant transient unreliable or unavailable. The inspectors evaluated the finding in accordance with IMC 0609, Significance Determination Process, Attachment 4, Phase 1 – Initial Screening. It was determined that a SDP Phase 2 analysis was required since the finding represented an actual loss of a safety function of a single train (EDG) for greater than its TS allowed outage time. The SDP Phase 2 analysis evaluated the finding for a loss of offsite power (LOSP) event and required a Phase 3 review. The risk associated with the second example involving the failed 2C32-K648 power supply was also aggregated into the Phase 3 because they share a common performance deficiency. This finding has potential safety significance greater than very low safety significance (Green) and is classified as an apparent violation.

A Phase 3 significance determination process (SDP) included independent analyses for the EDG timer card issue, and for the unit 2 reactor scram on June 23, 2009. The results were then aggregated into a single change-in-risk result. The dominant factor in the EDG result was the duration of the performance deficiency. Since the failure did not result in a timely alarm, the exact duration of the finding was determined by a T/2 calculation, where T is the time period since the last successful demonstration of the function. This resulted in an exposure time of almost one year. The finding was evaluated using the NRC's SPAR model for Hatch. The dominant risk sequences were LOSP, leading to station blackout and core damage upon failure of the high pressure systems. Fires leading to LOSP were also major risk contributors. Initial estimates for

Large Early Release Frequency (LERF) indicate it is a major driver of the significance of the event, but with more information these estimates may decrease. Additionally, the results from the Unit 2 reactor scram analysis show the dominant sequences were Anticipated Transient Without Scram (ATWS) sequences. The scram analysis assumed condensate remained available throughout the transient, and that main feedwater was recovered with a human error probability determined using the NRC's SPAR H methodology. The large early release frequency (LERF) risk was determined using the ATWS LERF multiplier from the Hatch phase 2 notebook. The aggregated risk was determined to be Greater Than Green due to the uncertainties associated with the LERF contribution.

Because the 2A and 1B EDG power supplies, timer cards, 2C EDG timer cards and 2C32-K648 power supply had their electrolytic capacitors replaced with new capacitors, and the licensee performed successful post maintenance testing on all timer cards and power supplies, this finding does not represent an immediate safety concern. The licensee has developed several interim corrective actions to address this issue until the long term design change is implemented on the Unit 2 EDG timer cards. One interim action includes a walk down of the timer card panels once a shift to verify that no errors exist on the timer cards and that the appropriate status lights are on. Another interim action includes a monthly functional test of the LOCA/LOSP timer cards to verify their proper operation. Additional corrective actions include an extent-of-condition review for the identification of power supplies that contain electrolytic capacitors and a schedule for replacement of any identified to be installed beyond their recommended service life. The Unit 1 LOSP circuitry is of an entirely different design and does not contain similar timer cards.

The inspectors determined this performance deficiency is indicative of current licensee performance, in that, licensee procedure NMP-ES-006 classifies the continuing equipment reliability improvement process at Southern Nuclear sites as a living preventive maintenance program. Additionally, information was available and reviewed by site personnel that documented the impacts of aged electrolytic capacitors on power supply reliability. Therefore, this finding has a cross-cutting aspect in the Operating Experience component of the Problem Identification and Resolution area, because the licensee did not implement and institutionalize operating experience through changes to station processes, procedures, equipment, and training programs. Specifically, the licensee did not make changes to station processes when internal and external operating experience indicated similar electrolytic capacitors failures were occurring. (P.2(b)).

Enforcement: TS 5.4.1 requires, in part, that procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978.

Regulatory Guide 1.33, Appendix A, section 9.b states, in part, preventive maintenance schedules should be developed to specify replacement of parts that have a specific lifetime.

Procedure NMP-ES-006, Predictive Maintenance Implementation and Continuing Equipment Reliability Improvement, is the licensee's current procedure which requires that component preventive maintenance activities be developed and scheduled to replace parts that have a specific lifetime. Specifically Section 5.4 of NMP-ES-006 requires, in part, that the licensee develop and maintain a documented maintenance strategy with recommended time-based preventive maintenance taking into account OEM/Vendor recommendations and other data affecting component reliability.

Contrary to the above, between 1988 and 2009, the licensee failed to implement site procedures to develop preventive maintenance schedules that specify replacement of electrolytic capacitors, which are parts that have been identified as having a specific lifetime, for Unit 2 EDG LOCA/LOSP timer cards and power supplies. Although the Unit 2 main feedwater median level controller 2C32-K648 power supply failure contributed to the overall risk assessment for Unit 2, it was not considered a violation because these components are non-safety related. These failures are identified in the licensee CAP as CR 2009102221 and 2009106352. Pending final determination of the safety significance, this finding is identified as an apparent violation (AV) 05000366/2009005-02, "Failure to establish appropriate preventative maintenance for electrolytic capacitors."

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the following five maintenance activities listed below to verify that risk assessments were performed prior to components being removed from service. The inspectors reviewed the risk assessment and risk management controls implemented for these activities to verify they were completed in accordance with licensee procedure 90AC-OAM-002-0, Scheduling Maintenance, and 10 CFR 50.65 (a)(4). For emergent work, the inspectors assessed whether any increase in risk was promptly assessed and that appropriate risk management actions were implemented.

- Oct 5 – Oct 9, excavation and modifications in the Thalmann switchyard, Unit 1 1A diesel generator battery charger preventive maintenance, Unit 2 A control rod drive pump preventive maintenance

- Oct 19 – Oct 22, Unit 1 reactor protection system voltage regulator preventive maintenance, Unit 1 reactor protection system power monitors calibrations, Unit 1 battery charger 1E preventive maintenance, Unit 1 B turbine building chiller maintenance, Unit 2 modifications in the Thalmann switchyard

- Oct. 24 – Oct. 30, U1 and U2 intake structure preservation – intake plugging, Thalmann switchyard modification, Unit 1 B train residual heat removal system outage

- Nov 2 – Nov 6, Unit 1 yellow risk during movement of large concrete barriers within the 230KV and 500KV switchyards, Unit 1 and Unit 2 intake structure preservation increased risk of intake plugging.

- Dec 5 – Dec 11, Unit 1A RHRSW pump breaker inspection, Unit 1 and 2 500KV switchyard excavation and modifications, Unit 2 RHRSW piping restraint repair, Unit 2 HPCI inoperable (12/7 to 12/11), Unit 2A LOCA/LOSP timer card calibration, Unit 2A EDG surveillance

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following three operability evaluations and compared the evaluations to the system requirements identified in the TS and the FSAR to ensure operability was adequately assessed and the system or component remained available to perform its intended function. Also, the inspectors assessed the adequacy of compensatory measures implemented as a result of the condition. Documents reviewed are listed in the Attachment.

- Unit 2 core spray with core spray line level switch, 2E21-N010A, inoperable
- Unit 1 1A emergency diesel generator lube oil leak
- Unit 1 & 2A main control room air conditioner degraded temperature controller

b. Findings

No findings of significance were identified.

1R18 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following plant temporary modification (TM) to ensure that safety functions of important safety systems have not been affected. Also, the inspectors verified that the design bases, licensing bases and performance capability of risk significant structures, systems and components have not been degraded through modifications. The inspectors verified that any modifications performed during increased risk-significant configurations did not place the plant in an unsafe condition. Documents reviewed are listed in the Attachment.

- TM 2-09-013 - 2P64B006A Drywell Chiller Motor Replacement, Rev. 2

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

For the following six post maintenance tests, the inspectors reviewed the test scope to verify the test demonstrated the work performed was completed correctly and the affected equipment was functional and operable in accordance with TS requirements. The inspectors reviewed licensee procedure 95IT-OTM-001-0, Maintenance Work Order Functional Test Guideline and also reviewed equipment status and alignment to verify the system or component was available to perform the required safety function. Documents reviewed are listed in the Attachment.

- WO 1092064302, “1 C EDG Control Panel,” replace damaged resistor and wiring, October 23
- 34SV-E11-002-1, “RHR Valve Operability,” preventive maintenance on RHR valves 1E11-F017B, 1E11-F027B, and 1E11-F119B, October 29
- WO 291461301, “2C11H34-43,” replace directional control valves for Unit 2 hydraulic control unit 34-43, November 12
- 34SV-R43-001-2, “EDG 2A Monthly Test,” repair lube oil piping coupling leak 2A EDG, November 13
- 52SV-R43-001-1, “Diesel Alternator and Accessories Inspection,” perform 24 month preventive maintenance inspections 1C EDG, November 19
- WO 1092854801, “1B EDG Jacket Cooling Water Heat Exchanger Leak,” repair plant service water leak for the 1B EDG cooler, December 24

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors reviewed licensee surveillance test procedures and either witnessed the test or reviewed test records for the following two surveillances to determine if the scope of the test adequately demonstrated the affected equipment was operable. The inspectors reviewed these activities to assess for preconditioning of equipment, procedure adherence, and equipment alignment following completion of the surveillance. The inspectors reviewed licensee procedure AG-MGR-21-0386, Evolution and Pre-and Post-Job Brief Guidance, and attended selected briefings to determine if procedure requirements were met. Documents reviewed are listed in the Attachment.

Reactor Coolant Leakage Test

- 34SV-SUV-019-1, Unit 1 drywell floor-drain leakage surveillance test

In-Service Test

- 34SV-E11-001-1, Unit 1 RHR pump operability

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed the emergency plan evolution conducted on October 14, 2009. The inspectors observed licensee activities in the simulator, Operations Support Center, and Technical Support Center to verify implementation of licensee procedure 10AC-MGR-006-0, Hatch Emergency Plan. The inspectors reviewed the classification of the simulated events and the development of protective action recommendations to verify these activities were conducted in accordance with licensee procedure 73EP-EIP-001-0, Emergency Classification and Initial Actions. The inspectors also reviewed licensee procedure 73EP-EIP-073-0, Onsite Emergency Notification, to verify the proper offsite notifications were made. The inspectors attended the post-exercise critique to assess the licensee's effectiveness in identifying areas of improvement. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors reviewed a sample of the licensee submittals for the performance indicators (PIs) listed below to verify the accuracy of the data reported. The PI definitions and the guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Rev. 5 and licensee procedure 00AC-REG-005-0S, Preparation and Reporting of NRC PI Data, were used to verify procedure and reporting requirements were met.

Cornerstone: Mitigating Systems Unit 1 & Unit 2

- Emergency AC Power System
- High Pressure Coolant Injection System
- Reactor Core Isolation Cooling System
- Residual Heat Removal System
- Residual Heat Removal Service Water System

- Plant Service Water System
- Safety System Functional Failures

Cornerstone: Barrier Integrity Unit 1& Unit 2

- Reactor Coolant System Leakage
- Reactor Coolant System Activity

The inspectors reviewed raw PI data collected since September, 2008 for the Initiating Events and Barrier Integrity indicators identified. The inspectors compared graphical representations from the most recent PI report to the raw data to verify the data was included in the report. The inspectors also examined a sampling of operations logs and procedures to verify the PI data was appropriately captured for inclusion into the PI report, and the individual PIs were calculated correctly. The inspectors observed a chemistry technician perform a sample of the reactor coolant system and a portion of the analysis in accordance with licensee procedure 64CH-SAM-025-0, "Reactor Coolant Sampling and Analysis." Applicable licensee event reports (LERs) issued during the referenced time frame were also reviewed. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Daily Screening of Corrective Action Items

As required by Inspection Procedure 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. This review was accomplished by either attending daily screening meetings that briefly discussed major CRs, or accessing the licensee's computerized corrective action database and reviewing each CR that was initiated.

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's Corrective Action Program and associated documents to identify trends which could indicate the existence of a more significant safety issue. The review was focused on repetitive equipment issues, but also considered the results of inspector daily CR screening, licensee trending efforts, and licensee human performance results. The review nominally considered the six month period of June 2009 through December 2009 although some examples extended beyond those dates when the scope of the trend warranted. The inspectors also reviewed several CRs associated with operability determinations which occurred during the period. The inspectors compared and contrasted their results with the results contained in the licensee's two latest quarterly trend reports. Corrective actions associated with a sample of the issues identified in the licensee's trend reports were reviewed for adequacy. The inspectors also evaluated the trend reports against the requirements of the licensee's corrective action program as specified in licensee procedure NMP-GM-002, Corrective Action Program, and 10 CFR 50, Appendix B. Documents reviewed are listed in the Attachment.

b. Findings and Observations

No findings of significance were identified.

4OA3 Event Follow-up

.1 Unit 1 Plant Transient Caused by the 2B Reactor Feed Pump Trip

a. Inspection Scope

The inspectors verified the licensee actions in response to the trip of the 2B reactor feed pump were in accordance with Emergency, Abnormal and Normal Operating Procedures. The inspectors verified the cause of the reactor feed pump trip was understood, reviewed chart recorders, operating logs and interviewed Operations staff on-shift during the transient.

b. Findings

No findings of significance were identified.

.2 (CLOSED) LER 05000321/2008-004 Power Supply Card Failure Causes Loss of Feedwater Flow Resulting in Manual Reactor Scram

a. Inspection Scope

On November 22, 2008, a Unit 1 manual reactor scram occurred as a result of low reactor water level due to a loss of reactor feedwater. The licensee determined the cause of the loss of reactor feedwater was due to failure of an electrolytic capacitor in the power supply for a Yokagawa differential pressure controller. The inspectors reviewed this LER, the licensee's root cause report and associated corrective actions. The inspectors determined that these documents identified a performance deficiency in that electrolytic capacitors for this power supply remained in service beyond the recommended service life. This issue was captured in the licensee's corrective action program as CR 2008111605. LER 05000321/2008-004 is closed.

b. Findings

Introduction: A Green self-revealing finding was identified for the licensee's failure to establish and perform preventive maintenance activities to replace electrolytic capacitors as required per licensee procedure, NMP-ES-006, Predictive Maintenance Implementation and Continuing Equipment Reliability Improvement. The failure to replace electrolytic capacitors led to failures of power supplies which directly resulted in Unit 1 manual reactor scram on November 22, 2008 (LER 05000321/2008-004).

Description: On November 22, 2008 a manual reactor scram was inserted on Unit 1 due to unexpected lowering of reactor water level. The direct cause of reactor water level decreasing was failure of Yokagawa controller DC power supply 1N21-K088 which provides power to differential pressure controller for the steam jet air ejector inter-condenser cooling water control valve. With loss of power to the differential pressure controller, valve 1N21-F211 failed closed thereby isolating the main condensate 30-inch line to the condensate demineralizers. This in turn caused a loss of reactor feedwater flow when 1A condensate booster pump, 1A reactor feed pump, and 1B reactor feed pump each tripped on low suction pressure.

The cause of the 1N21-K088 DC power supply failure was attributed to failure of electrolytic capacitors within the power supply. The licensee classified this power supply as a critical component, in a mild service environment, with a low duty cycle. The licensee's preventive maintenance optimization (PMO) template specifies a minimum 12 year refurbishment and 20 year replacement strategy for this type of power supply. EPRI Power Supply Application and Maintenance Guide 1003096 dated 12/01 recommends replacing electrolytic capacitors or the entire power supply every 7.5 years for power supplies classified as critical, mild environment, low duty cycle. As of November 22, 2008 the 1N21-K088 power supply had been in-service for 14 continuous years with no preventive maintenance to replace the electrolytic capacitors in this power supply. Contrary to the EPRI recommendations and the site preventive maintenance optimization program, the licensee failed to establish suitable preventive maintenance to replace the 1N21-K088 power supply to prevent electrolytic capacitor age-related failure. This issue was captured in the licensee's corrective action program as CR 2008111605.

Analysis:

Failure to establish and perform electrolytic capacitor preventive maintenance activities to replace aged electrolytic capacitors as required per licensee procedure, NMP-ES-006, Predictive Maintenance Implementation and Continuing Equipment Reliability Improvement is a performance deficiency. This performance deficiency is more than minor because it is associated with the Equipment Performance attribute of the Initiating

Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during power operations, in that, on November 22, 2008 the 1N21-K088 power supply failed which led to a manual reactor scram for Unit 1. This performance deficiency also affected the reliability and availability of mitigating systems in that the performance deficiency led to a trip of main feedwater pumps while at power requiring manual action to restore feedwater, which is a mitigating system providing high pressure makeup. The significance of this finding was screened with NRC Inspection Manual Chapter 0609 Attachment 4, and since it contributed to an increase in the likelihood of a reactor trip and affected the reliability and availability of mitigating system equipment, a phase 2 assessment was required. The phase 2 review with the Hatch pre-solved worksheet did not have an appropriate column to evaluate the finding therefore a phase 3 significance determination process (SDP) was required. A phase 3 SDP analysis was performed by a regional SRA, as a loss of main feedwater initiating event assessment using the NRC's SPAR model. The result was <1E-6 for conditional core damage probability and <1E-7 for conditional large early release probability, a GREEN finding. The dominant sequences were ATWS sequences. The analysis assumed condensate remained available throughout the transient, and that main feedwater was recovered with a human error probability determined using the NRC's SPAR H methodology. The LERF risk was determined using the ATWS LERF multiplier from the Hatch phase 2 notebook. This finding does not represent a current safety concern because the Unit 1 Yokagawa controller DC power supply 1N21-K088 for the steam jet air ejector inter-condenser cooling water control valve has been replaced.

The inspectors determined this performance deficiency is indicative of current licensee performance, in that, licensee's procedure NMP-ES-006 classifies the continuing equipment reliability improvement process at Southern Nuclear sites as a living preventive maintenance program and information was available and reviewed by site personnel documenting aged electrolytic capacitors caused reduced reliability of components. Therefore, this finding has a cross-cutting aspect in the Operating Experience component of the Problem Identification and Resolution area, because the licensee did not implement and institutionalize operating experience through changes to station processes, procedures, equipment, and training programs. Specifically, the licensee did not make changes to station processes when internal and external operating experience indicated similar electrolytic capacitors supply failures were occurring. (P.2(b)).

Enforcement:

Enforcement action does not apply because the performance deficiency did not involve a violation of regulatory requirements due to it being associated with the non-safety related feedwater system. Because this finding does not involve a violation of regulatory requirements and has very low safety significance, it is identified as FIN 05000321/2009-005-03, "Failure to establish and perform preventive maintenance activities to replace aged electrolytic capacitors for Yokagawa controller power supply."

.3 (CLOSED) LER 05000366/2009-004 Turbine Trip On High Reactor Water Level Due to Failed Circuit Board Results in Reactor Scram

a. Inspection Scope

On June 23, 2009, an automatic reactor scram occurred as a result of turbine trip due to high reactor water level. The licensee determined the cause of the high reactor water level was failure of an electrolytic capacitor in the power supply for a Yokagawa water level controller. The inspectors reviewed this LER, the licensee's root cause report and associated corrective actions. The inspectors identified a performance deficiency in that electrolytic capacitors for this power supply remained in service beyond the vendor recommended service life. This issue was captured in the licensee's corrective action program (CAP) as CR 2009106352. This LER is closed. See section 1R12.2 for additional information.

b. Findings

Findings for this LER closure are discussed in section 1R12.2.

.4 (CLOSED) LER 05000321/2008-001 Leak in Reactor Pressure Boundary Piping Due to a Crack Caused by Intergranular Stress Corrosion Cracking

a. Inspection Scope

On March 6, 2008 a leak was discovered in one-inch instrumentation pipe during the reactor pressure vessel system leakage test while Unit 1 was cold shutdown. It was later determined that the leakage was part of the reactor coolant system boundary and the cause was due to intergranular stress corrosion cracking (IGSCC). This condition was captured in the licensee's CAP as CR 2008103067. The enforcement aspects of this finding are discussed in Section 4OA7. This LER is closed.

b. Findings

The inspectors determined the circumstances identified in this LER resulted in a licensee-identified very low safety significant violation of regulatory requirements. The enforcement aspects of this finding are discussed in Section 4OA7.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

.2 Operation of an Independent Spent Fuel Storage Installation (ISFSI) (IP 60855.1)

a. Inspection Scope

The inspectors performed a walkdown of the ISFSI on site (reference docket 72-036) and monitored the activities associated with the dry fuel storage campaign which completed October 23. The inspectors also reviewed changes made to the ISFSI programs and procedures and their associated 10 CFR 72.48 screens and evaluations to verify that changes made were consistent with the license or Certificate of Compliance; reviewed records to verify that the licensee has recorded and maintained the location of each fuel assembly placed in the ISFSI; and reviewed surveillance records to verify that daily surveillance requirements were performed as required by technical specifications. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

.3 (CLOSED) URI 05000321,366/2009006-04 Reactor Building Equipment Drain Sump System for Units 1 and 2

a. Inspection Scope

During the component design bases inspection performed from May 4 – July 20, 2009, the team identified an unresolved item (URI) regarding the licensee's failure to scope and monitor the Reactor Building Equipment Drain Sump System (RBEDS) for Units 1 and 2 in the maintenance rule program. The issue was unresolved pending further inspection and interface with the licensee to determine the extent of condition and impact from the failure to scope and monitor the RBEDS system in the licensee's maintenance rule program and to determine the impact of the single failure design deficiency for the sump level switches. Two findings are discussed below.

b. Findings

.1 Introduction: The NRC identified a Green non-cited violation of 10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, for the failure to scope the monitoring of the Unit 1 and Unit 2 RBEDS system into the licensee's maintenance rule program.

Description: The Unit 1 and 2 RBEDS system is used during postulated events such as a feedwater piping or fire main ruptures to automatically or manually prevent the propagation of waters between the torus room and the diagonal rooms. The diagonal rooms house High Pressure Core Injection (HPCI), Reactor Core Injection Cooling (RCIC), Control Rod Drive, Core Spray, and Residual Heat Removal components. The RBEDS is comprised of piping, sumps, sump pumps, level switches, check valves, and air operated valves (AOV). The AOVs are automatically closed by actuation of select level switches or manually closed by operators from the control room. The FSAR states that the RBEDS is equipped with level alarms and a system of remotely operated valves to prevent flooding of compartments other than the one in which a leak occurs. Additionally, the FSAR states that no single failure of the instrumentation prevents any of the protective actions from occurring.

The RBSEDS system was initially scoped into the Maintenance Rule Scoping Manual on May 12, 1994. The team noted that the RBEDS system was removed from the Scoping Manual during a revision on July 10, 1996. The result of the 1996 revision is that the RBEDS system has not been monitored in the licensee's maintenance rule program since 1996. The inspectors determined that RBEDS system should be monitored in the licensee's maintenance rule program because:

- The failure of the RBEDS system could adversely affect safety-related equipment during postulated events such as a main feedwater line pipe rupture.
- The RBEDS system level indication is used in the emergency operating procedures (31EO-EOP-014-1/2S) to indicate abnormal leakage to secondary containment.
- The licensee's flood analysis assumes the automatic closure of the RBEDS AOVs.
- The licensee's risk model credits the flood isolation functions of the RBEDS system.

The team's review of the equipment history (2005 – 2009) revealed numerous and repetitive failures of AOVs on Units 1 and 2. The licensee initiated condition reports (2009105110 and 20091051110) and administratively closed all AOVs until maintenance and design issues are resolved.

Analysis: The team determined that the licensee's failure to scope the RBEDS system into the maintenance rule program was a performance deficiency. This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to monitor and establish goals that would have addressed repetitive AOV failures in the RBEDS system, resulted in a lack of assurance that the system would reliably perform its safety function during a design bases internal flooding event. The team determined that a phase 3 assessment was required using the SDP because the finding screened as potentially risk significant due to flooding scenarios with the potential to degrade the RCIC or HPCI systems; and, the finding represented an actual loss of safety function of one or more non-Tech Spec Trains of equipment designated as risk-significant per 10CFR50.65, for >24 hrs. A phase 3 analysis was performed by a regional SRA utilizing the NRC Hatch SPAR model with a result <1E-6 for core damage frequency (CDF) and <1E-7 for large early release frequency (LERF). The dominant sequences were loss of main feedwater (LOMFW) due to main feedwater line pipe rupture in the steam tunnel resulting in flooding of reactor building corner rooms due to failure of the reactor building floor drain isolation valves. Flooding of the corner rooms would cause the loss of either the RCIC or HPCI system. The finding was characterized as of very low safety significance (Green). The risk was low because of the availability of either RCIC or HPCI for all scenarios and due to the exposure period and low pipe rupture frequencies. The team evaluated the finding for cross-cutting aspects and determined that this performance deficiency was a historical issue so as to not reflect current licensee performance.

Enforcement: 10 CFR 50.65(a)(1) states, in part, that licensee's shall monitor the performance or condition of structures, systems and components (SSCs) within the scope of the rule as defined by 10 CFR 50.65 (b), against licensee established goals, in a manner sufficient to provide reasonable assurance that such SSCs are capable of fulfilling their intended function.

10 CFR 50.65 (b)(2) requires, in part, that the scope of the monitoring program specified in paragraph (a)(1) shall include non-safety related structures, systems, and components (SSCs) that are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures.

Contrary to the above, as of July 10, 1996, the licensee failed to include a non-safety related system into it's maintenance rule scope that is relied upon to mitigate accidents and is used in plant EOPs. Specifically, the licensee failed to scope the Unit 1 and Unit 2 RBEDS system into their maintenance rule monitoring program and failed to monitor the system in a manner sufficient to provide reasonable assurance that the RBEDS AOVs were capable of fulfilling their intended function when repetitive failures. Because this violation was determined to be of very low safety significance (Green) and has been entered into the licensee's corrective action program as CR 2009105110 and 2009105111, it is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 05000321,366/2009005-04, "Reactor Building Equipment Drain Sump System Not Scoped into Maintenance Rule."

.2 Introduction: The NRC identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control, for the failure to translate the design bases as stated in the FSAR into specifications for Units 1 and 2. Specifically, single failure design criteria for the reactor building sump level instrumentation has not been met since initial plant operation.

Description: To mitigate the effects of internal flooding for Units 1 and 2, the torus rooms and the reactor building diagonal rooms are equipped with instrumented floor drain sumps. The instrumented sumps are equipped with sump level switches that automatically close AOVs when high water levels are detected to prevent the spread of water from room to room. The activation of the sump level switches and closure of the

AOVs protects equipment in the diagonal rooms. The diagonal rooms house HPCI, RCIC, Control Rod Drive, Core Spray, and RHR components.

The team noted the following: FSAR Section 9.3.3, states that no single failure of the level instrumentation prevents any of the protective actions from occurring; the licensee's flood analysis assumed the automatic closure of the AOVs; and, the sump level instrumentation was classified as non-safety. As a result of the team's questioning, the licensee initiated CR 2009105731 which revealed that sump level switches T45-N006 and T45-N007 were not single failure proof as stated in the FSAR. Using actual as-built design information for the level switches (not single failure proof) the licensee performed an evaluation, Flooding of the Torus Room and Diagonals (RER C091204801) to determine the flooding effects if level switch T45-N006 or T45-N007 (Unit 1 or 2) failed. RER C091204801 determined that a main feedwater line break with a postulated single failure of the Unit 1 level switch (1T45-N007) would result in the loss of RCIC system, and a failure of the Unit 2 level switches (2T45-N006 or 2T45-N007) would result in the loss of the HPCI system or RCIC systems. The licensee initiated CRs (2009105744, 2009105110, 2009105111, 2009105615, and 2009105727) and administratively closed the AOVs as an interim compensatory measure.

Analysis: The team determined that the licensee's failure to install single failure proof level switches as stated in the UFSAR was a performance deficiency. This finding is more than minor because it is associated with the design control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, a failure of a level switch would adversely impact the automatic closure of flood isolation valves that protect safety-related equipment during a design bases internal flooding event. The team determined that a phase 3 assessment was required because the finding screened as potentially risk significant due to flooding scenarios with the potential to degrade the RCIC or HPSI systems. A phase 3 analysis was performed by a regional SRA utilizing the NRC Hatch SPAR model with a result <1E-6 for core damage frequency (CDF) and <1E-7 for large early release frequency (LERF). The dominant sequences were loss of main feedwater (LOMFW) due to main feedwater line pipe rupture in the steam tunnel resulting in flooding of reactor building corner rooms due to failure of the level switches to provide closure signals to the reactor building floor drain isolation valves. Flooding of the corner rooms would cause the loss of either the RCIC or HPCI system. The finding was characterized as of very low safety significance (Green). The risk was low because of the availability of either RCIC or HPCI for all scenarios and due to the low pipe rupture frequencies. The team evaluated the finding for cross-cutting aspects and determined that this performance deficiency was a historical issue so as to not reflect current licensee performance.

Enforcement: 10 CFR 50, Appendix B, Criterion III, Design Control, requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. These measures shall include provisions to assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

Contrary to the above, since initial plant operation the licensee failed to assure that the design basis as stated in the FSAR was correctly translated into specifications for the Unit 1 and Unit 2 sump level switches. Specifically, the installed level switches (T45-N006 and T45-N007) on Units 1 and 2 do not meet FSAR design criteria for being single failure proof. Because this violation was determined to be of very low safety significance (Green) and has been entered into the licensee's corrective action program as CR 2009105731, 2009105744, 2009105110, 2009105111, 2009105615, and 2009105727, it is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 05000321,366/2009005-05, "Reactor Building Equipment Drain Sump Level Detection is Not Single Failure Proof."

.4 (CLOSED) URI 05000321,366/2009006-03 Non-Interruptible Essential Instrument Air Header Check Valves for Units 1 and 2

a. Inspection Scope

During the component design bases inspection performed from May 4 – July 20, 2009, the team identified a URI regarding non-interruptible essential instrument air header check valves for Units 1 and 2. The licensee had not performed periodic maintenance or testing that demonstrated the capability of the check valves to prevent back-flow during a loss of instrument air event. The issue was unresolved pending further inspection and interface with the licensee to determine the extent of condition and impact from the lack of periodic maintenance or testing.

b. Findings

Introduction: The NRC identified a Green non-cited violation of 10 CFR 50.65, Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, for the licensee's failure to monitor the Non-interruptible Essential Instrument Air Check Valves in a manner sufficient to provide reasonable assurance that the components were capable of fulfilling their intended function.

Description: FSAR Section 9.3.1, Compressed Air Systems, states that the instrument air system is divided into two subsystems, non-interruptible and interruptible. The non-interruptible system provides instrument air for the operation of certain emergency system components. If a leak or pipe break causes low instrument air header pressure, a non-redundant safety grade nitrogen system automatically supplies the non-interruptible essential air system with long term compressed gas. The non-interruptible essential air headers are designed with two check valves in series that function as a boundary between instrument air and non-interruptible essential air. The boundary check valves prevent the loss of back-up nitrogen through postulated breaks in the instrument air system. The licensee scoped the function of the non-interruptible essential air system into the maintenance rule program as documented in the Performance Criteria dated June 19, 1998. The team noted that an EOP utilized the back-up nitrogen system for operation of the hardened containment vent during loss of instrument air events, which is a dominant contributor to the plant's overall core damage frequency risk profile.

The team determined that since initial plant start-up of Units 1 and 2, the licensee has not performed periodic maintenance or testing to demonstrate the capability of the check valves to prevent back-flow during a loss of instrument air event. The lack of periodic maintenance or testing resulted in a lack of reasonable assurance that the valves could perform their design function if called upon. The licensee initiated CR 2009105109 and established compensatory measures to mitigate a loss of instrument air event if the non-interruptible boundary check valves fail to prevent back leakage of nitrogen through a postulated instrument air pipe rupture.

<u>Analysis</u>: The team determined that the licensee's failure to perform periodic maintenance on non-interruptible essential instrument air header check valves was a performance deficiency. This finding is more than minor because it is similar to example 7.d. of Inspection Manual Chapter 0612, Appendix E, and because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to perform periodic maintenance or testing of the check valves resulted in a lack of reasonable assurance that the non-interruptible essential air system would provide sufficient capability to operate the hardened containment vent during a loss of instrument air event. The failure to operate the containment hardened vent would adversely affect the mitigation function of the decay heat removal system. Using the SDP, the team determined that a phase 3 assessment was required because the finding screened as potentially risk significant due to actual loss of safety function of one or more non-Tech SpecTrains of equipment designated as risk-significant per 10CFR50.65, for >24 hrs. Based on the lack of maintenance or testing since initial plant start-up, the team assumed that the check valves were not capable of performing their safety function. A phase 3 assessment was required because the phase 2 notebook did not have a loss of instrument air initiator worksheet. A phase 3 risk assessment was performed by a regional SRA utilizing data from the licensee's full scope model with a result <1E-6 for core damage frequency (CDF) and <1E-7 for large early release frequency (LERF). The dominant sequences were loss of instrument air due to instrument air pipe rupture and check valve failure with operators failing to align systems for decay heat removal. The risk was of very low safety significance (Green) for both CDF and LERF due to the low frequency for pipe rupture and the high likelihood for operators to recover in the available time. Additionally, the system design had all valves failing to the desired position on loss of air except for the containment vent function which had a specific proceduralized recovery using portable air bottles. The team evaluated the finding for cross-cutting aspects and determined that this performance deficiency was a historical issue so as to not reflect current licensee performance.

<u>Enforcement</u>: 10 CFR 50.65(a)(1) states, in part, that licensee's shall monitor the performance or condition of structures, systems and components (SSCs) within the scope of the rule as defined by 10 CFR 50.65 (b), against license established goals, in a

manner sufficient to provide reasonable assurance that such SSCs are capable of fulfilling their intended function.

10 CFR 50.65(a)(2) states, in part, that monitoring as specified in (a)(1) is not required where it has been demonstrated that the performance or condition of a component is being effectively controlled through the performance of appropriate preventive maintenance such that the SSC remains capable of fulfilling its intended function.

Contrary to the above, the licensee failed to demonstrate that the performance or condition of the non-interruptible essential instrument air boundary check valves had been effectively controlled through the performance of appropriate preventive maintenance and did not monitor performance against licensee established goals. Specifically, since initial plant start-up, the licensee failed to perform preventative maintenance to assure the capability of the check valves to maintain the non-interruptible essential air header pressurized with nitrogen during a loss of instrument air event. Because this violation was determined to be of very low safety significance (Green) and has been entered into the licensee's corrective action program as CR 2009105109, it is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 05000321,366/2009005-06, "Failure to Monitor the Non-interruptible Instrument Air Check Valves."

4OA6 Meetings, Including Exit

On February 10, 2010 and on January 29, 2010, the resident inspectors presented the inspection results to you and other members of your staff. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

On January 14, 2010, via teleconference, regional inspectors presented the in-office inspection results for two URIs that are discussed in section 4OA5 of this report. Mr. Dennis Madison and members of your staff acknowledged the three findings associated with the URIs. The NRC confirmed proprietary information was not provided or examined during the in-office inspection.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- Unit 1 Technical Specification 3.4.4, RCS Operational Leakage, requires no RCS pressure boundary leakage while operating in Modes 1, 2 and 3. Contrary to this, on May 2, 2008, the licensee reported that RCS pressure boundary leakage existed while the unit was in Mode 1. The leakage was discovered to be from a pin-hole located in a one-inch stainless steel original instrument pipe for the 'A' main steam line flow instrument. The cause of the leak was found to be intergranular stress corrosion cracking (IGSCC). The stress on this pipe was attributed to poor weld fit up of the pipe and poor weld quality that both existed since original construction. Also, it was discovered that a pipe restraint was not installed as required by the plant's piping drawing. This issue was documented in CR 2008103067. The affected piping was replaced prior to restart of the unit. The violation was determined to be of very low safety significance in that the unidentified leakage into the drywell, assuming worst case degradation of the pin hole leak, was approximately 0.05 gallons per minute (gpm) of the TS allowable limit of 5 gpm for unidentified leakage. In addition the violation did not affect the ability of other mitigating systems to perform their safety function.

- 10 CFR 50 Appendix B, Criterion V, states in part that activities affecting quality shall be prescribed by documented instructions of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions. Contrary to this requirement, the licensee discovered that both redundant timing relays for the 2G 4160 VAC emergency switchgear were not calibrated per the licensee's calibration procedure 57CP-CAL-204-0. During a surveillance test on March 31, 2009, it was discovered that both relays had failed to actuate which prevented the 2C EDG output breaker to close as expected. Because Unit 2 entered a RFO on February 9 and the last successful surveillance of these relays occurred on February 28 and the failure occurred during a RFO, the finding was evaluated in accordance with NRC inspection manual chapter 0609 Appendix G, Shutdown Operations SDP. Checklist 8 in attachment 1 of Appendix G was appropriate for plant conditions at the time of discovery. Using the checklist, the inspectors determined that the licensee maintained an adequate mitigation capability in four of the five shutdown safety functions and a Phase 2 and Phase 3 analysis was not required. Therefore, the finding screens as Green. The licensee entered this finding into their CAP as CRs 2008100277 and 2009103473.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel
S. Bargeron, Plant Manager
G. Brinson, Operations Manager
J. Dixon, Health Physics Manager
B. Hulett, Engineering Design Manager
G. Johnson, Engineering Director
J. Lewis, Site Support Manager
D. Madison, Hatch Vice President
S. Soper, Engineering Support Manager
J. Thompson, Nuclear Security Manager
R. Varnadore, Maintenance Manager

LIST OF ITEMS OPENED AND CLOSED

Opened

05000321,366/2009005-01	URI	Submerged safety-related medium voltage cables (1R06.2)
05000366/2009005-02	AV	Failure to establish appropriate preventative maintenance for electrolytic capacitors (1R12.2)

Closed

05000321/2008-004	LER	Power Supply Card Failure Causes Loss of Feedwater Flow Resulting in Manual Reactor Scram (4OA3.2)
05000366/2009-004	LER	Turbine Trip On High Reactor Water Level Due to Failed Circuit Board Results in Reactor Scram (1R12.2, 4OA3.3)
05000321/2008-001	LER	Leak in Reactor Pressure Boundary Piping Due to a Crack Caused by Intergranular Stress Corrosion Cracking (4OA3.4)
05000366/2009002-04	URI	Failure of Unit 2 EDG LOCA/LOSP Timer Cards (1R12.2)
05000321/2009006-03 and 05000366/2009006-03	URI	Non-Interruptible Essential Instrument Air Header Check Valves for Units 1 and 2 (Section 4OA5.4)
05000321/2009006-04 and 05000366/2009006-04	URI	Reactor Building Equipment Drain Sump System for Units 1 and 2 (Section 4OA5.3)

Opened & Closed

05000321/2009005-03	FIN	Failure to establish and perform preventive maintenance activities to replace aged electrolytic capacitors for Yokagawa controller power supply (4OA3.2)
05000321/2009005-04 and 05000366/2009005-04	NCV	Reactor Building Equipment Drain Sump System Not Scoped into Maintenance Rule (Section 4OA5.3.1)
05000321/2009005-05 and 05000366/2009005-05	NCV	Reactor Building Equipment Drain Sump Level Detection is Not Single Failure Proof (4OA5.3.2)
05000321/2009005-06 and 05000366/2009005-06	NCV	Failure to Monitor the Non-interruptible Instrument Air Check Valves (Section 4OA5.4)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Procedures:
34SV-E11-002-1, RHR Valve Operability, Ver. 18.10
34SV-E11-001-1, Residual Heat Removal Pump Operability, Ver. 23.9
34SO-E11-010-1, Residual Heat Removal System, Ver. 34.0
Edwin I. Hatch Nuclear Plant Unit 1 Technical Specification Bases, section B 3.5.1
34SO-R43-001-1, Diesel Generator Standby AC System, Ver. 23.8
90AC-OAM-002-0, Scheduling Maintenance, Ver. 3.1

Drawings:
H-16330, Unit 1 RHR System P&ID, sheet 2, Ver. 62.0
H-26007, Control Rod Drive System P&ID, sheet 2, Ver. 45.0
H-26006, Control Rod Drive System P&ID, sheet 1, Ver. 29.0
S-25311, Control Rod Drive Hydraulic System, Rev. 1

Other:
UFSAR Edwin I. Hatch Nuclear Power Plant, Section 4.8, Residual Heat Removal
UFSAR Edwin I. Hatch Nuclear Power Plant, Section 4.2.3.2.2.3, Control Rod Drive Hydraulic System

Section 1R05: Fire Protection

Procedures:
34AB-X43-001-1, Fire Procedure, Ver. 10.21
34SO-X43-005-0, Diesel Generator Building Carbon Dioxide System, Ver. 0.7

Drawings:
A-43966, Sheets 8, 9, 12, 13, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26
A-43965, Sheet 23

Other:
NL-09-0442, Updated Request for Extension of 10 CFR 50 Appendix R Enforcement Discretion

Section 1R06: Internal Flood Protection

Procedures:
34AR-657-901-2, Annunciator Response Procedures for Control Panel 2H11-P657, Alarm Panel 1, Ver. 22.13
31EO-EOP-014-2, SC-Secondary Containment Flowchart, Ver. 8
73EP-EIP-001-0, Emergency Classification and Initial Actions, Ver. 17.0
NMP-ES-051, Cable Monitoring Program, Ver. 1.0
52PM-Y46-001-0, Inground Pullbox and Cable Duct Inspection for Water, Ver. 6.10

Condition Reports:
2009111808

Documents:
Hatch Unit 2 Internal Floods Analysis, dated December 1992
Intracompany Correspondence – Response to NRCIN 2005-11 & NRCIN 2005-30, dated June 2005
Hatch Individual Plant Examination, dated October 1994
Intracompany Correspondence – Response to NRCIN 2002-012, Submerged Safety-Related electrical Cables, dated July 9, 2002

Section 1R11: Licensed Operator Requalification

Drill Scenario LT-SG-50918-00, Condensate Booster Pump, Condenser Air In-Leakage, Loss of Vacuum, ATWS
73EP-EIP-001-0, Emergency Classification and Initial Actions
31EO-EOP-011-2, RCA RPV Control (ATWS)
31EO-EOP-017-2, CP-3 ATWS Level Control
31EO-EOP-103-2, Rod Insertion Methods
34AB-N61-002-2, Main Condenser Vacuum Low
34AB-C71-001-2, Scram Procedure
34SO-C41-003-2, Standby Liquid Control System

Section 1R12: Maintenance Effectiveness

Drawing:
H-43801, Ver. 7.0
H-23358, Ver. 18
H-23815, Ver. 27

H-23670, Ver. 20.0
H-23669, Ver. 19.0
H-27517, Ver. 16.0
H-23804, Ver. 16.0
H-23698, Ver. 21.0
H-23776, Ver. 20.0
H-23587, Ver. 23
H-23588, Ver. 10.0
B-23361, Ver. 0.1, Sheets 3 and 4
H-23699, Ver. 21.0
H-23700, Ver. 23.0
H-23697, Ver. 21.0
H-23777, Ver. 27.0
H-23357, Ver. 25.0
H-23371, Ver. 26.0
H-23358, Ver. 18

Procedures:
34SV-P41-003-2, Standby Service Water System Operability, Ver. 4.7
34SV-P41-003-2, Standby Service Water System Operability, 1/26/2006
34SV-P41-003-2, Standby Service Water System Operability, 4/10/2006
34SV-P41-003-2, Standby Service Water System Operability, 7/3/2006
34SV-P41-003-2, Standby Service Water System Operability, 9/30/2006
34SV-P41-003-2, Standby Service Water System Operability, 12/18/2006
34SV-P41-003-2, Standby Service Water System Operability, 4/30/2007
34SV-P41-003-2, Standby Service Water System Operability, 12/10/2007
34SV-P41-003-2, Standby Service Water System Operability, 6/19/2008
34SV-P41-003-2, Standby Service Water System Operability, 3/19/2009
34SV-P41-003-2, Standby Service Water System Operability, 7/2/2009
34SV-P41-003-2, Standby Service Water System Operability, 7/22/2009
34SV-P41-003-2, Standby Service Water System Operability, 7/23/2009
34SV-P41-003-2, Standby Service Water System Operability, 8/21/2009
34SV-P41-003-2, Standby Service Water System Operability, 9/19/2009
34AR-650-903-2, APR's for Control Panel 2H11-P650 Alarm Panel 3, Ver. 20.11
57CP-CAL-204-0, Struthers Dunn Time Delay Calibration Procedure, Ver. 8.9
42SV-R43-016-2S, Diesel Generator 2C LOCA/LOSP LSFT, Ver. 10.1
42SV-R43-018-2, Diesel Generator 2A Logic System Function Test, Ver. 6.7, dated 2/13/2009
42SV-R43-020-2S, Diesel Generator 2C Logic System Function Test, Ver. 4.6
NMP-GM-002, Corrective Action Program, Ver. 2.0
34AB-R23-001-2, Loss of 600 Volt Emergency Bus, Ver. 1.5
34AB-R22-003-2, Station Blackout, Ver. 3.6

Other:
MCR logs
Plant Hatch response to Generic Letter 89-13
Plant Service Water (PSW) System Health Report, 2nd quarter 2009
Inservice Testing (IST) Scoping Manual, 4th interval
Maintenance Rule (MR) Scoping Document

Plant Service Water MR monthly report, August 2009
2R43 Emergency Diesel Generator System MR report, August 2009
2R43 Emergency Diesel Generator System MR report, July 2009
2R43 Emergency Diesel Generator System MR report, June 2009
2R43 Emergency Diesel Generator System MR report, May 2009
2R43 Emergency Diesel Generator System MR report, April 2009
2R43 Emergency Diesel Generator System MR report, March 2009
2R43 Emergency Diesel Generator System MR report, February 2009
WO 1090906601, RHRSW Pump 1C lower guide bearing high temperature alarm
WO 2050735901, Diesel 2C LOCA Timer
WO 2050735902, Diesel 2C LOCA Timer
WO 2050735903, Diesel 2C Leading Timer Panel
WO 2050740901, Diesel 2A Leading Timer Panel
Required Action Sheet (RAS) 2-05-037
Letter 94-154, SCS Letter on RHRSW Motor Bearing Temperature Setpoints, dated July 22, 1994
1E11-2E11, Residual Heat Removal System Health Report, 2nd Quarter 2009

Condition Reports:
2007100686, 2007107708, 2009102452, 2009108187, 2009106710, 2009108156, 2009104395, 2008100277, 2009103473, 2009103536, 2005103415, 2005103484, 2008107899, 2008107935, 2009101237, 2009101880, 2009102221, 2005111157,

Section 1R13: Maintenance Risk Assessments and Emergent Work Evaluation
Procedures:
90AC-OAM-002-0, Scheduling Maintenance, Ver. 3.1
34SV-R43-003-2, Diesel Generator 2C Monthly Test, Ver. 21.28
57IT-MIC-004-2, Testing the LOCA/LOSP Timer Cards, Ver. 1.7
57SV-S32-002-2, Emergency Buses 2E, 2F, and 2G Undervoltage Relay FT&C, Ver. 12.13

Other:
Main Control Room (MCR) logs
2009111541, Evaluating plant risk with scheduled plan of the Day (POD) work

Drawing:
H23777

Section 1R15: Operability Evaluations
Condition Reports:
2009109435, Core spray line level A switch would not actuate during calibration
2009109933, 2A EDG lube oil leak discovered during semi-annual surveillance test

Procedures:
NMP-AD-012, Operability Determinations and Functional Assessments, Ver. 6.0
42SV-Z41-005-0, Control Room Capacity Verification, Ver. 3.2, dated 11/6/2009

Other:
MWO 1072842101

Prompt Determinations of Operability:
PDO 01-09-07

Section 1R18: Plant Modifications
Procedures:
52PM-MNT-013-0, Chiller Maintenance, Ver. 4.1

Maintenance Work Orders:
2091712606
2091712601
2091712610

Other:
Reptask 2P64B006A5, Grease 2P64B006A Motor Bearings
Reptask N1P63B001A1, Acquire vibration readings on U1/U2 chillers
Engineering Evaluation No. 1854

Section 1R19: Post Maintenance Testing
Maintenance Work Orders (MWOs): 1092064302, 1072706601, 1082684101, 106202601, 1081028801, 2091461301, 2092028602, 1092854801

Procedures:
34SV-E11-002-1, RHR Valve Operability, Ver 18.10
AG-OAM-01-0600, Outage Readiness Review, Ver. 1.1
34SV-R43-001-2, Diesel Generator 2A Monthly Test, Ver. 25.30

Drawings:
H-13403, Ver. 13.0
H-13414, Ver. 44.0
H-13621, Ver. 20.0
H-26006, Ver. 29.0

Condition Reports:
2009110114, 2009110080, 20091110189, 2009110193, 2009108160, 2008107083, 2009110833, 2009112067, 2009112068

Action Item: 2008203896

Section 1R22: Surveillance Testing
Procedures:
34SV-E11-001-1, Residual Heat Removal Pump Operability, Ver 23.9
34SV-SUV-019-1, Surveillance Checks, Ver 33.36

Section 1EP6: Drill Evaluation
Emergency preparedness exercise narrative and timeline for drill conducted 10/14/09
Emergency notification forms from drill conducted 10/14/09

Section 4OA1: Performance Indicator Verification
MSPI Consolidated Date Entry (CDE) and Margin Reports
Hatch MSPI Basis Document Version D
Other: Main Control Room Operating Logs
LERs: 1-2009-001, 1-2009-002, 1-2009-003, 1-2009-004, 1-2009-005, 2-2009-001, 2-2009-002, 2-2009-003, 2-2009-004

Section 4OA2: Identification and Resolution of Problems
CAP Trend Summary Report May 2009 through July 2009
CAP Trend Summary Report August 2009 through October 2009

Section 4OA5: Other Activities
Dry Cask Storage – 10 CFR 72.212 Report – Revision for 2009 Loading Campaign
Fuel Assembly Certification Datasheets
42FH-ERP-014-OS, Fuel Movement, Ver 17.9
Fuel Movement Sheets 2009 Dry Storage loading 2009-001 & 2009-002
RER C091204801, Flooding of Torus Room and Diagonals, dated 7/16/09