UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

October 29, 2010

Mr. Jon A. Franke
Vice President, Crystal River Nuclear Plant
Crystal River Nuclear Plant (NA2C)
15760 W. Power Line Street
Crystal River, FL 34428-6708

SUBJECT: CRYSTAL RIVER UNIT 3 – NRC INTEGRATED INSPECTION REPORT 05000302/2010004

Dear Mr. Franke:

On September 30, 2010, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Crystal River Unit 3. The enclosed integrated inspection report documents the inspection findings which were discussed on October 12, 2010, with Mr. J. Holt and other members of your staff.

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

Based on the results of this inspection, three NRC identified findings of very low safety significance (Green) were identified. The findings were determined to involve violations of NRC requirements. However, because of the very low safety significance of the issues and because they were entered into your corrective action program, the NRC is treating the issues as a non-cited violations (NCVs) consistent with the NRC Enforcement Policy. If you contest 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 20555-001; 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 Crystal River Unit 3 site. In addition, if you disagree with the cross-cutting aspect assigned to 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, RII, and the NRC Resident Inspector at Crystal River Unit 3.

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

Sincerely,

/RA/

Daniel W. Rich, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Docket No. 50-302
License No. DPR-72

Enclosure: Inspection Report 05000302/2010004
w/Attachment: Supplemental Information

cc w/encl: (See next page)

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cc w/encl:
R. J. Duncan, II
Vice President
Nuclear Operations
Carolina Power & Light Company
Electronic Mail Distribution

Brian C. McCabe
Manager, Nuclear Regulatory Affairs
Progress Energy Carolinas, Inc.
Electronic Mail Distribution

James W. Holt
Plant General Manager
Crystal River Nuclear Plant (NA2C)
Electronic Mail Distribution

Stephen J. Cahill
Engineering Manager
Crystal River Nuclear Plant (NA2C)
Electronic Mail Distribution

R. Alexander Glenn
Associate General Counsel
(MAC - BT15A)
Florida Power Corporation
Electronic Mail Distribution

Christos Kamilaris
Director
Fleet Support Services
Carolina Power & Light Company
Electronic Mail Distribution

William A. Passetti
Chief
Florida Bureau of Radiation Control
Department of Health
Electronic Mail Distribution

Daniel R. Westcott
Supervisor
Licensing & Regulatory Programs
Crystal River Nuclear Plant (NA1B)
Electronic Mail Distribution

Joseph W. Donahue
Vice President
Nuclear Oversight
Carolina Power and Light Company
Electronic Mail Distribution

Jack E. Huegel
Manager, Nuclear Oversight
Crystal River Nuclear Plant
Electronic Mail Distribution

David T. Conley
Associate General Counsel
Legal Dept.
Progress Energy Service Company, LLC
Electronic Mail Distribution

Mark Rigsby
Manager, Support Services - Nuclear
Crystal River Nuclear Plant (NA2C)
Electronic Mail Distribution

Senior Resident Inspector
U.S. Nuclear Regulatory Commission
Crystal River Nuclear Generating Plant
U.S. NRC
6745 N Tallahassee Rd
Crystal River, FL 34428

Attorney General
Department of Legal Affairs
The Capitol PL-01
Tallahassee, FL 32399-1050

Ruben D. Almaguer
Director
Division of Emergency Preparedness
Department of Community Affairs
Electronic Mail Distribution

Chairman
Board of County Commissioners
Citrus County
110 N. Apopka Avenue
Inverness, FL 36250

Letter to J. Franke from Daniel W. Rich dated October 29, 2010

SUBJECT: CRYSTAL RIVER UNIT 3 – NRC INTEGRATED INSPECTION REPORT 05000302/2010004

Distribution w/encl:
C. Evans, RII
L. Douglas, RII
OE Mail (email address if applicable)
RIDSNRRDIRS
PUBLIC
RidsNrrPMCrystal River Resource

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No.:	50-302
License No.:	DPR-72
Report No.:	05000302/2010004
Licensee:	Progress Energy (Florida Power Corporation)
Facility:	Crystal River Unit 3
Location:	Crystal River, FL
Dates:	July 1, 2010 – September 30, 2010
Inspectors:	T. Morrissey, Senior Resident Inspector R. Reyes, Resident Inspector E. Crowe, Senior Resident Inspector Farley R. Chou, Reactor Inspector (Section 4OA5)
Approved by:	D. Rich, Chief, Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000302/2010004; 07/01/2010-09/30/2010, Crystal River Unit 3; Flood Protection Measures Other Activities.

The report covered a three month period of inspection by resident inspectors and one reactor engineer. There Green NCVs were identified. The significance of most findings is identified by their color (Green, White, Yellow, Red) using IMC 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The cross-cutting aspect is determined using IMC 0310, Components Within The Cross-Cutting Areas. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process", Revision 4, dated December 2006.

A. NRC Identified & Self-Revealing Findings

Cornerstone: Mitigating Systems

Green. The inspectors identified a non-cited violation (NCV) of 10 CFR 50 Appendix B, Criterion III, "Design Control," regarding the licensee's failure to ensure that the design bases of two components were correctly translated into specifications, drawings, procedures, and instructions. Specifically, licensee personnel failed to ensure that two floor penetration flood barriers (metal sleeves) were of the proper height to prevent water from entering the A train decay heat removal (DHR)/building spray (BS) vault during a design basis internal flooding event. The design basis did not assume any leakage to the vault. The licensee initiated nuclear condition report (NCR) 409263 in the corrective action program to address the issue.

This finding is more than minor because it affects the design control attribute of the mitigating system cornerstone, and affected the cornerstone objective of ensuring availability, reliability, and capability of systems that respond to initiating events. Using Manual Chapter 0609, Phase 1 screening worksheet, the inspectors determined that the finding has very low safety significance because it did not result in a loss of any system safety function. The inspectors found that the cause of the finding is not reflective of current performance and therefore, a cross-cutting aspect will not be assigned. (Section 1R06)

Green. The inspectors identified an NCV, with five examples, of Crystal River Unit 3 Operating License Condition 2.C (9), fire protection program. The NCV was associated with one inoperable fire penetration seal in the ceiling of the B train decay heat and building spray pump vault and four inoperable fire penetration seals associated with the main steam piping in the wall between the intermediate building and the turbine building. Once identified, the licensee initiated an hourly watch and entered the issue in the corrective action program as nuclear condition reports 369096, 406215, and 418755.

The finding is more than minor because if left uncorrected, the fire seals could experience further degradation and potentially lead to a more significant safety concern.

Using NRC IMC 0609, Appendix F, Fire Protection Significance Determination Process, the inspectors assessed the defense-in-depth (DID) element of each fire barrier degradation in the fire confinement category. One penetration was determined to have a low degradation rating and was determined to be of very low safety significance. The other four degraded penetrations were determined to have moderate degradation and were screened to be very low safety significance due to having non-degraded automatic full area water-based fire suppression system available in the exposing fire area. A contributing cause of the finding is related to the cross-cutting area of Problem Identification and Resolution with an evaluation aspect (P.1.(c)). Specifically, the licensee had the opportunity to evaluate the need to change the frequency of main steam line fire penetration inspections after finding degradation of main steam piping penetrations in 2007. (Section 4OA5)

Cornerstone: Barrier Systems

Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion IX, "Control of Special Processes," for the licensee's failure to establish measures to assure that testing of rebar splices would adhere to the requirements of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code. Specifically, licensee procedures for containment building repairs did not accommodate rebar production splice testing, which was required by Code. As part of their immediate corrective actions, the licensee revised their procedures to include production splice testing and also entered the issue into their corrective action program.

The inspectors determined that the finding was more than minor because it was associated with the human performance attribute of the barrier systems cornerstone and affected the cornerstone objective of ensuring the reliability of containment wall barrier system. Failure to adhere to ASME Code testing requirements can adversely affect assurance that the rebar splices would meet strength requirements as part of the containment barrier. The inspectors completed a Phase 1 screening of the finding using Inspection Manual Chapter 0609, "Significance Determination Process," Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings" and determined that the performance deficiency represented a finding of very low safety significance (Green). Specifically, the finding did not result in the actual loss of function of the Unit 3 Containment Wall. This finding has a cross-cutting aspect in the area of Human Performance under the "Effectiveness Reviews" aspect of the "Decision-Making" component because the licensee failed to validate assumptions used as a basis for their decision to pursue an alternative testing plan. [H.1(b)] (Section 4OA5)

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status:

Crystal River 3 began the inspection period with the full core off-loaded to the spent fuel pool. The unit remained in this condition for the remainder of the inspection period.

REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

.1 Partial Equipment Walkdowns

a. Inspection Scope

The inspectors performed walkdowns of the critical portions of the selected trains to verify correct system alignment. The inspectors reviewed plant documents to determine the correct system and power alignments, and the required positions of select valves and breakers. The inspectors verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact mitigating system availability. The inspectors verified the following three partial system alignments in system walkdowns using the listed documents:

- A train 4160 and 480 Volt AC Engineered Safeguards (ES) Buses, using Operating Procedures OP-700, 6900, 4160, and 480 Volt AC Buses, and OP-209A, Plant Shut Down and Cool Down, while the emergency diesel generator (EGDG)-1B was out of service for maintenance
- A train decay heat removal (DHR), decay heat closed cycle (DC), raw water (RW) pump RWP-2A and RWP-3A, using OP-404, Decay Heat Removal System and OP-408, Nuclear Service Cooling System, while the B train of emergency core cooling system was out of service for maintenance
- Off site power breaker alignment and EGDG-1B, using OP-707, Operation of the ES Emergency Diesel Generators, and SP-321, Power Distribution Breaker Alignment and Power Availability Verification, while the A and C EGDGs were out of service for planned maintenance

b. Findings

No findings were identified.

.2 Complete System Walkdown

a. Inspection Scope

The inspectors conducted a detailed walkdown/review of the alignment and condition of both trains of the core flood system. The inspectors used licensee operating procedure, OP-401, Core Flood System, as well as design documents, and reviewed the applicable portions of the Final Safety Analysis Report (FSAR) to verify proper system alignment. This completes one sample of a complete system alignment.

The walkdown included evaluation of selected system piping and supports against the following considerations:

- Piping and pipe supports did not show evidence of water hammer
- Oil reservoir levels indicated normal
- Snubbers did not indicate any observable hydraulic fluid leakage
- Component foundations were not degraded
- No fire protection hazards
- Temporary scaffolding had been installed per station procedures

A review of outstanding maintenance work orders was performed to verify that any deficiencies did not significantly affect the system function. In addition, the inspectors reviewed nuclear condition reports (NCRs) to verify that system problems were being identified and appropriately resolved.

b. Findings

No findings were identified.

1R05 Fire Protection

Fire Area Walkdowns

a. Inspection Scope

The inspectors walked down accessible portions of the plant to assess the licensee's implementation of the fire protection program. The inspectors checked that the areas were free of transient combustible material and other ignition sources. Also, fire detection and suppression capabilities, fire barriers, and compensatory measures for fire protection problems were verified. The inspectors checked fire suppression and detection equipment to determine whether conditions or deficiencies existed which could impair the function of the equipment. The inspectors selected the areas based on a review of the licensee's probabilistic risk assessment. The inspectors also reviewed the licensee's fire protection program to verify the requirements of FSAR Section 9.8, Plant Fire Protection Program, were met. Documents reviewed are listed in the attachment. The inspectors toured the following five areas important to safety:

- Emergency Feed Pump EFP-3 Building
- Emergency diesel generator EGDG-1B control and engine rooms
- A train ES 4160 VAC switchgear room
- A and B train spent fuel pump and heat exchanger area
- Feed water pump FWP-7 area

b. Findings

No findings were identified.

1R06 Flood Protection Measures

Internal Flood Protection

a. Inspection Scope

The Inspectors reviewed the Crystal River Unit 3, FSAR, Chapter 2.4.2.4, Facilities Required for Flood Protection, Surveillance Procedure SP-407, Fire and Flood Barrier Penetration Seals Inspection, and the Crystal River Unit 3 Design Basis Documents that depicted protection for areas containing safety-related equipment to identify areas that may be affected by internal flooding. A walk down of the auxiliary building A train DHR vault was conducted to ensure that flood protection measures were in accordance with design specifications. Specific plant attributes that were checked included structural integrity, sealing of penetrations, and operability of sump systems.

b. Findings

Introduction. The inspectors identified a Green non-cited violation (NCV) of 10 CFR 50 Appendix B, Criterion III, "Design Control," regarding the licensee's failure to ensure that the design bases of two components were correctly translated into specifications, drawings, procedures, and instructions. Specifically, licensee personnel failed to ensure that two floor penetration flood barriers (metal sleeves) were of the proper height to prevent water from entering the A train decay heat removal (DHR)/building spray (BS) vault during a design basis internal flooding event. The design basis did not assume any leakage to the vault.

Description. On July 8, 2008, in preparation for a surveillance test, the inspectors walked down the A train DHR removal system. On the 95' elevation of the auxiliary building (AB), the inspectors determined that the height of a flood barrier around penetration PAB-182 measured about a half inch shorter than required for a design basis internal flood event (7 inch flood) as described in the FSAR (sections 9.5.2.1.6 and 9.5.2.3.2). This short sleeve would allow water to enter the A train DHR/BS vault during this design basis event. The inspectors also identified that abnormal procedure, AP-1040, Auxiliary Building Flooding, contained an incorrect note that stated "If AB 95 Ft flood level exceeds 2 ft DH Vaults will flood." Both issues were placed in the licensee's corrective action program as NCRs 409263 and 410139.

The licensee confirmed that the flood barrier around penetration PAB-182 did not meet the height requirement for a flood event as described in the FSAR. An extent of condition walkdown by the licensee found a second shorter than required flood barrier around penetration PAB-183. The flood barriers for penetrations PAB-182 and PAB-183 were measured by the licensee to be 6.5 inches and 6.25 inches, respectively. Both penetrations are in the reactor bleed tank room on the AB 95' elevation and contain decay heat closed cycle cooling piping that enters the A train DHR/BS vault on the 75' elevation.

In 1989, the licensee recognized the need to install encapsulation sleeves around the circulating water (CW) expansion joints (CWEJ) to prevent a CWEJ rupture impacting auxiliary building safety-related equipment. Later it was determined that the same type of encapsulation sleeves were needed for the raw water system expansion joints (RWEJ). As a result, the licensee implemented modification approval records MAR 86-09-15-01 and MAR 90-08-16-01 to install encapsulation sleeves on the CW and RW expansion joints. The sleeves were designed to limit auxiliary building flooding to less than 7 inches with no operator action for 30 minutes. The 7 inch limit was determined to be the critical flood height for safety-related equipment in the auxiliary building.

The design basis for internal flood events for the auxiliary building is a 90 inch CWEJ failure in the turbine building and a 36 inch RWEJ in the auxiliary building. Calculation M91-0019, Allowable Gaps for the RWEJ Encapsulation Sleeves, predicts a 6.71 inch flood height for a RWEJ failure after 30 minutes. Calculation M91-1002, Circulating Water Expansion Joint Encapsulation, predicts a 6.48 inch flood height for a CWEJ failure after 30 minutes. Both calculations contained a design input that specified 7 inches as the critical flood level for the AB 95' elevation.

The licensee determined that with a minimum flood barrier height of 6.25 inches for PAB-183, a bounding internal flood height of 6.71 inches would allow approximately 7,200 gallons to spill over the flood barrier into the A train DHR/BS vault. This would result in a flood of 5.9 inches in the vault. The licensee determined that a flood level of 26 inches would be required before impacting equipment in the vault. The inspectors confirmed this to be the case.

This issue was entered into the licensee's corrective action program as NCR 409263. Corrective actions planned include the installation of protective sleeves on the two flood barriers to prevent flood water from entering the A train DHR/BS vault. This corrective action would restore the validity of the design input associated with the 7 inch critical flood level for both the above referenced calculations.

<u>Analysis.</u> The performance deficiency associated with this finding involved the licensee's failure to comply with the requirements of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." Specifically, licensee personnel failed to recognize that the height of the sleeves around two penetrations was less than the critical flood height used in determining the design requirements of the RWEJ and CWEJ encapsulation sleeves. This finding is more than minor because it affects the design control attribute of the

mitigating system cornerstone, and affected the cornerstone objective of ensuring availability, reliability, and capability of systems that respond to initiating events. Using Manual Chapter 0609, Phase 1 screening worksheet, the inspectors determined that the finding has very low safety significance because it did not result in a loss of any system safety function. The inspectors found that the cause of the finding is not reflective of current performance and therefore, a cross-cutting aspect will not be assigned.

Enforcement. 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that the design basis of certain structures, systems, and components be translated into specifications, drawings, procedures, and instructions. Contrary to this requirement, from about 1990 to July 8, 2010, licensee personnel failed to recognize that the design basis internal flooding calculations did not accurately reflect the configuration of the plant. Specifically, licensee personnel failed to ensure that design basis flooding calculations (M91-0019, Allowable Gaps for the RWEJ Encapsulation Sleeves and M91-1002, Circulating Water Expansion Joint Encapsulation), accurately reflected the configuration of the plant. Both calculations were based on a critical flood height of 7 inches in the AB. The inspectors identified two floor penetration flood barriers (metal sleeves) that were not of the proper height to prevent water from entering the A train DHR/BS vault during a design basis internal flooding event. The design basis did not assume any leakage to the vault. Because the finding is of very low safety significance and has been entered into the licensee's corrective action program as NCR 409263, this violation is being treated as an NCV consistent with the NRC Enforcement Policy: NCV 05000302/2010004-01, Flood Calculations did not Reflect Plant Configuration.

1R11 Licensed Operator Requalification Program

Resident Inspector Quarterly Review

a. Inspection Scope

On July 27, and September 28, 2010, the inspectors observed and assessed licensed operator crew response and actions for the Crystal River Unit 3 licensed operator simulator evaluated session SES-52 and SES-31, respectively.

Session SES-52 involved a steam leak on a main steam line, a manual reactor trip, a reactor coolant system (RCS) over cooling event, and an RCS leak in containment. The inspectors observed the operator's use of emergency operating procedures EOP-02, Vital System Status Verification, and EOP-05, Excessive Heat Transfer and abnormal procedure AP-520, Loss of RCS Coolant or Pressure.

Session SES-31 involved a failure of a main steam line followed by a loss of coolant accident that was beyond the capability of the normal makeup system. The unit was manually tripped and during the transient there was a loss of adequate sub-cooling margin. The inspectors observed the operator's use of EOP-02; AP-770, Emergency Diesel Generator Actuation, and EOP-03, Inadequate Sub-cooling Margin.

In both sessions, the operator's actions were verified to be in accordance with the above procedures. Event classification and notifications were verified to be in accordance with emergency management procedure EM-202, Duties of the Emergency Coordinator. The simulator instrumentation and controls were verified to closely parallel those in the actual control room. The inspectors attended the management crew critique and evaluation to verify the licensee had entered any adverse conditions into the corrective action program. The inspectors evaluated the following attributes related to crew performance:

- Clarity and formality of communication
- Ability to take timely action to safely control the unit
- Prioritization, interpretation, and verification of alarms
- Correct use and implementation of abnormal and emergency operation procedures; and emergency plan implementing procedures
- Control board operation and manipulation, including high-risk operator actions
- Oversight and direction provided by supervision, including ability to identify and implement appropriate technical specification actions, regulatory reporting requirements, and emergency plan classification and notification
- Crew overall performance and interactions

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee's effectiveness in performing routine maintenance activities. The review included the identification, scope, and handling of degraded equipment conditions, as well as common cause failure evaluations, and the resolution, of historical equipment problems. For those systems, structures, and components within the scope of the Maintenance Rule (MR) per 10 CFR 50.65 (a)(1) and (a)(2) classifications were justified in light of the reviewed degraded equipment condition. The documents reviewed are listed in the attachment. The inspectors conducted this inspection for the following issue:

- NCR 372292 Radiation Monitor RM-A1 failure causing atmospheric radiation monitoring (RM) system to be classified MR a(1)

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

Inspection procedure IP 71111.13, Maintenance Risk Assessments and Emergent Work Control, specifies verification of performance of risk assessments for planned or emergent maintenance activities during all modes of operation. Due to the extended no mode condition, i.e., full core off loaded to the spent fuel pool, to support reactor building containment repair, there were no opportunities for inspection in this area during the inspection period. Outage related risk assessment monitoring was performed under section 1R20.

1R15 Operability Evaluations

Due to the extended no mode condition, i.e., full core off loaded to the spent fuel pool, to support reactor building containment repair, there were no opportunities for inspection in this area during the inspection period.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors witnessed and/or reviewed post-maintenance test procedures and/or test activities, as appropriate, for selected risk significant systems to verify whether: (1) testing was adequate for the maintenance performed; (2) acceptance criteria were clear, and adequately demonstrated operational readiness consistent with design and licensing basis documents; (3) test instrumentation had current calibrations, range, and accuracy consistent with the application; (4) tests were performed as written with applicable prerequisites satisfied, and (5) equipment was returned to the status required to perform its safety function. The five post-maintenance tests reviewed are listed below:

- SP- 354C, Functional Test of the Alternate AC Diesel Generator EGDG-1C, after performing planned maintenance per work orders (WOs) 01668920 and 01793249.
- SP-354B, Monthly Functional Test of the Emergency Diesel Generator EGDG-1B, after performing planned maintenance per WOs 1716303 and 1496944
- SP-354A, Functional Test Of The Emergency Diesel Generator EGDG-1A, after performing planned maintenance per WO 1769320
- Performance Test PT-236, EFIC Power Supply Testing, after performing planned maintenance per WO 1035762
- SP-340B, DHP-1A, BSP-1A and Valve Surveillance, after performing maintenance per WOs 1529824 and 1499873

b. Findings

No findings were identified.

1R20 Refueling and Outage Activities

Steam Generator Replacement Refueling Outage (RFO16)

a. Inspection Scope

On September 26, 2009, the unit was shut down for a steam generator replacement refueling outage. NRC integrated inspection reports 05000302/2009005, 05000302/2010002 and 05000302/2010003 documented NRC outage inspection activities prior to this inspection period. The inspectors observed and monitored licensee controls over the refueling outage activities listed below. Additional inspection results for RFO16 will be documented in next quarter's NRC integrated inspection report 05000302/2010005. Documents reviewed are listed in the Attachment.

- Outage related risk assessment monitoring
- Controls associated with reactivity management, electrical power alignments, and spent fuel pool cooling
- Implementation of equipment clearance activities

b. Findings

During the creation of a temporary opening in the reactor containment building to support steam generator replacement, the licensee discovered an internal crack in the vicinity of the temporary opening. The circumstances associated with the crack in the containment wall were by assessed by an NRC special inspection team. The results of this inspection are documented in NRC special inspection report 05000302/2009007.

b. Findings

No findings were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed and/or reviewed five surveillance tests listed below to verify that ITS surveillance requirements were followed and that test acceptance criteria were properly specified. The inspectors verified that proper test conditions were established as specified in the procedures, that no equipment preconditioning activities occurred, and that acceptance criteria had been met. Additionally, the inspectors also verified that equipment was properly returned to service and that proper testing was specified and conducted to ensure that the equipment could perform its intended safety function following maintenance or as part of surveillance testing.

In-Service Test:

- SP-340B, DHP-1A, BSP-1A and Valve Surveillance (DHP-1A only)

Surveillance Test:

- SP-340A, RWP-3A, DCP-1A And Valve Surveillance
- SP-300, Operating Daily Surveillance Log (auxiliary building and outside area Logs)
- SP-375B, CHP-1B and Valve Surveillance

Containment Isolation Valve Test:

- SP-179C, Containment Leakage Test – Type “C” (Penetration 377, makeup system)

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

Initiating Events and Mitigating Systems Cornerstones

a. Inspection Scope

The inspectors checked licensee submittals for the PIs listed below for the period July 1, 2009 through June 30, 2010 to verify accuracy. Performance indicator definitions and guidance contained in NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Rev. 6, were used to check the reporting for each data element. The inspector checked licensee events reports, operator logs, and daily plant status reports to verify the licensee accurately reported the data including the number of critical hours reported. The inspectors checked that any deficiencies affecting the licensee’s performance indicator program were entered into the corrective action program (CAP) and appropriately resolved.

- Safety System Functional Failures

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution

.1 Daily Review

a. Inspection Scope

As required by Inspection Procedure 71152, Identification and Resolution of Problems, and in order to help identify equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished by attending daily plant status meetings, interviewing plant operators and applicable system engineers, and accessing the licensee's computerized database.

b. Findings

No findings were identified.

.2 Annual Sample Review

a. Inspection Scope

The inspectors selected four priority 2 condition reports, NCR 362346, 370660, 379949, and 395045 for a detailed review and discussion with the licensee. The NCRs were written to address the failures associated with the reactor building air handling fan AHF-1A. The failures had originally not been classified as MR functional failures. However, the misclassifications were later identified and the MR expert panel entered the fan into MR (a)(1). The inspectors checked that the issues had been completely and accurately identified in the licensee's corrective action program; safety concerns were properly classified and prioritized for resolution, apparent cause determination was sufficiently thorough, appropriate corrective actions were initiated, MR functional failure classifications had been corrected and adequately characterized, and the MR (a)(1) goals and monitoring period were adequate to return the fan to MR (a)(2). The inspectors also evaluated the NCRs using the requirements of the licensee's CAP as delineated in corrective action procedure CAP-NGGC-200, Corrective Action Program.

b. Findings and Observations

No findings were identified. The reactor building air handling fan AHF-1A had tripped three times, and there had been a condition report and a MR evaluation completed for each trip. However, engineering had misclassified the trips as not being MR functional failures. Once the misclassifications were identified, immediate corrective actions included: initiating NCR 395045; reevaluating whether the MR reliability criteria had been exceeded; the responsible engineering personnel were counseled on the difference in terminology and the program requirements regarding multiple equipment failures; and the MR Program manager provided a department-wide lessons learned communication to clarify the MR Program requirements. The air handling fan was subsequently entered into MR (a)(1) and goals and a monitoring period were assigned. The inspectors found the MR goals and monitoring period were adequate. However, in reviewing the individual NCRs, the inspector identified that the licensee had not made corrections to the CAP documents to reflect that the failures had been reclassified as MR functional failures. Additionally, CAP procedure CAP-NGGC-200 requires a priority 2A NCR be initiated to evaluate the MR program aspects when exceeding a reliability criteria. The inspector found that the 2A NCR had not been initiated and no justification had been documented in the CAP. The inspectors reviewed the CAP issues with the licensee and the licensee acknowledged the issues. The licensee made corrections to the CAP documents by revising all the condition reports to show that the failures had been reclassified as functional failures. Additionally, NCR 379949 was revised and provided a justification for not initiating a 2A NCR.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel 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 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 reviews and inspection activities.

b. Finding

No findings were identified.

.2 Closed Unresolved Item (URI) 05000302/2010003-01, Degraded Fire/Flood Barriers

Inspection Scope

The inspectors completed a review and analysis of completed and proposed licensee corrective actions associated with URI 05000302/2010003-01. The inspectors determined that the degraded fire/flood barriers were a violation of regulatory requirements.

Findings

Introduction: The inspectors identified a Green NCV, with five examples, of Crystal River Unit 3 Operating License Condition 2.C(9), fire protection program. The NCV was associated with one inoperable fire penetration seal in the ceiling of the B train decay heat and building spray pump vault and four inoperable fire penetration seals associated with the main steam piping in the wall between the intermediate building and the turbine building.

<u>Description</u>: On April 27, during a fire inspection walkdown of the auxiliary building 95' elevation, the inspectors found a degraded silicon foam fire seal in penetration PAB-125. PAB-125 is a combination 3-hour rated fire penetration and a flood barrier that contains makeup system piping. The penetration separates fire area AB-75-4 (B train decay heat removal (DHR)/building spray (BS) vault) from fire area AB-95-8 (nuclear service booster pump room). PAB-125 is also qualified as a flood seal. Closer examination revealed a through-penetration gap (less than 1/8 inch in width) between the pipe and the silicon foam. The gap extended approximately 180 degrees around the circumference of the pipe. Light was observed passing through the penetration from the DHR/BS vault below. The licensee declared fire penetration PAB-125 inoperable; initiated an hourly fire watch in accordance with Fire Protection Plan, Table 6.7a; and documented the condition in the corrective action program as NCR 369095. The licensee determined that no compensatory measures were necessary for the degraded flood feature of the penetration due to the current plant condition. This seal was last inspected in the late 1990's.

The licensee investigation of degraded penetration PAB-125 determined that the degradation was most likely caused by a combination of pipe movement, normal shrinkage of the silicon foam material, and environmental exposure. Corrective actions proposed included repair of the penetration.

On June 22, 2010, during a fire inspection walkdown of the intermediate building 119' elevation, the inspectors identified two additional degraded fire seals (PIB-35 and PIB-36). Penetrations PIB-35 and PIB-36 are 3-hour rated fire penetrations associated with the A train main steam system piping. The penetrations separate fire area IB-119-201 in the intermediate building from fire area TB-119-400 in the turbine building. Fire area IB-119-201 contains B train safety- related cables. It appeared that the silicon foam seal had pulled away from one side of each penetration. The widest width of the through-penetration gap was about 1 inch. The licensee declared both 3-hour rated fire penetrations PIB-35 and PIB-36 inoperable; initiated an hourly fire watch in accordance with Fire Protection Plan, Table 6.7a; and documented the condition in the corrective action program as NCR 406215. These fire seals were last inspected in May 2008 when the plant was operating.

The licensee investigation determined that the movement of the main steam piping due to thermal effects caused the gap in the seal to open when the plant was shut down September 2009 for the current plant outage. Proposed licensee corrective actions include: repairing PIB-35 and PIB-36 in accordance with design requirements; determine the appropriate inspection period for those fire penetrations that may be affected by changing plant conditions; perform a 100 percent inspection of fire/flood seals per SP-407; and determine whether the frequency of inspection for fire/flood seals needs to be adjusted.

On August 27, 2010 during the extent of condition inspection, the licensee determined that the two B train main steam piping penetrations (PIB-37 and PIB-38) were in the same degraded condition as the A train penetrations due to movement of the main steam piping. Both penetrations separate intermediate building fire area IB-119-201 from fire area TB-119-400 in the turbine building. PIB-37 and PIB-38 were declared inoperable, hourly fire watches were established and the condition as entered into the corrective action program as NCR 418755. In 2007, PIB-37 and PIB-38 were declared inoperable when some of the fiber penetration material was found to have come out of the penetration. The penetrations were repaired and the issue was placed in the corrective action program as NCR 225494.

Analysis: The failure to identify five inoperable fire penetration seals represented a licensee performance deficiency. Specifically, the inspection frequency as specified in SP-407, Fire and Flood Barrier Penetration Seals Inspection, Revision 34, did not allow for timely licensee identification and repair of the degraded fire seals. SP-407 specifies an inspection frequency that would result in each seal being inspected at least once every 15 years. The licensee did not consider changing plant conditions when determining this inspection frequency. The finding adversely affected the fire confinement capability defense-in-depth element. The finding is more than minor because if left uncorrected, the fire seals could experience further degradation and potentially lead to a more significant safety concern. Regarding the ability of PAB-125 to act as a flood barrier, the inspectors determined that the degradation would have little impact on its flood barrier capability. Therefore, the inspectors determined that the degradation with respect to the ability to act as a flood barrier is minor and will not be evaluated under the NRC significance determination process.

Using NRC Inspection Manual Chapter (IMC) 0609, Appendix F, Fire Protection Significance Determination Process, the inspectors assessed the defense-in-depth (DID) element of the PAB-125 fire barrier degradation in the fire confinement category. Since the gap in the silicon foam fire penetration seal was small (less than 1/8 inch in width), the degradation level was categorized as low (IMC 0609, Appendix F, Attachment 2, Table A2.2). IMC 0609, Appendix F, Attachment 1, Task 1.3.1, Qualitative Screening for all Finding Categories, showed that the finding was of very low safety significance (Green) due to the low degradation rating.

Using NRC IMC 0609, Appendix F, Fire Protection Significance Determination Process, the inspectors assessed the defense-in-depth (DID) element of the PIB-35 and PIB-36 fire barriers degradation in the fire confinement category. Since the through-penetration gap in the silicon foam fire penetration seal was greater than 3/8 inch in width, the degradation level was categorized as Moderate B (IMC 0609, Appendix F, Attachment 2, Table A2.2). IMC 0609, Appendix F, Attachment 1, Task 1.3.2, Supplemental Screening for Fire Confinement Findings, Question 3, screened the finding to very low safety significance (Green) due to having non-degraded automatic full area water-based fire suppression system available in the exposing fire area.

Using NRC IMC 0609, Appendix F, Fire Protection Significance Determination Process, the inspectors assessed the defense-in-depth (DID) element of the PIB-37 and PIB-38 fire barriers degradation in the fire confinement category. Since the through-penetration gap in the mineral wool fire penetration seal was between 1 inch and 2 inches in width, the degradation level was categorized as Moderate B (IMC 0609, Appendix F, Attachment 2, Table A2.2). IMC 0609, Appendix F, Attachment 1, Task 1.3.2, Supplemental Screening for Fire Confinement Findings, Question 3, screened the finding to very low safety significance (Green) due to having non-degraded automatic full area water-based fire suppression system available in the exposing fire area.

A contributing cause of the finding is related to the cross-cutting area of Problem Identification and Resolution with an evaluation aspect (P.1.(c)). Specifically, in 2007 the licensee had the opportunity to evaluate the need to change the frequency of main steam line fire penetration inspections after finding degradation of penetrations PIB-37 and PIB-38.

Enforcement: Crystal River Unit 3 Operating License Condition 2.C(9) requires, in part, that the licensee implement and maintain in effect all provisions of the approved fire protection program. The Crystal River Unit 3 Fire Protection Plan, Revision 28, Section 6.5.1.3, Penetration Seals, specifies that surveillance procedure SP-407, Fire and Flood Barrier Penetration Seals Inspection, Revision 34, be utilized to ensure the seal functions as an approved fire barrier. SP-407, section 3.6.3.1, states, in part, that there will be NO passage of light through sealant and that there are NO cracks greater than 1/8 inch in width in functional portion of sealant.

Contrary to the above, on April 27, 2010 the inspectors found a through-penetration gap that allowed passage of light through fire seal PAB-125; on June 22, 2010, the inspectors found through-penetration gaps greater than 1/8 inch in width in fire seals PIB-35 and PIB-36; and on August 27, 2010, during the extent of condition inspection, through-penetration gaps greater than 1/8 inch in width were found in fire seals PIB-37 and PIB-38. The licensee initiated hourly fire watches and documented the inoperable fire seals in the corrective action program as NCRs 396095, 406215 and 418755. Corrective action will include repair to the seals. Because this finding is of very low safety significance and was entered into the licensee’s corrective action program, this finding is being treated as an NCV, consistent with the NRC Enforcement Policy. This finding is identified as NCV 05000302/2010004-02, Inoperable Fire Barrier Penetration Seals.

.3 Steam Generator Replacement Project and Containment Wall Repair (IP 50001)

a. Inspection Scope

The inspectors conducted a review of the licensee’s Phase 3 of concrete and crack removal and surface preparation, and Phase 4 of concrete placement activities for the repair of the containment wall delamination and reinstallation of the containment wall opening created during the Steam Generator Replacement Project (SGRP) in the last quarter of 2009.

Concrete and Crack Removal

The inspectors observed the process of the hydro demolition for concrete removal and hydro lancing for the crack removal. The inspectors reviewed and examined cracks in the upper elevation above Elevation 176’ after the removal of 12 to 22 inches of concrete to address the delamination. The inspectors examined horizontal and vertical cracks and reviewed the crack removal above and to the side of the containment wall opening after concrete removal of 10 to 12 inches for the delamination and extended concrete excavation beyond the vertical tendon sleeves. The inspectors reviewed NCR 00395843, Concrete Removal Exposed Horizontal and Vertical Cracks. The inspectors also observed the surface preparation of concrete after the hydro demolition and lancing and pull-out testing in the upper elevation that the licensee conducted to verify the adequacy of the bond between the new and old concrete. The inspectors reviewed vertical cracks from the core borings in this bay and other bays where the vertical cracks extended to the liner plate. The inspectors also reviewed the findings on old cracks identified by impulse response testing and the core borings that showed cracks below repair areas and were not removed during the repair of the dome delamination. The inspectors reviewed the radial rebar drilling, grouting, and resolution of voids for the elevation below 176’.

Rebar and Formwork Installation

The inspectors examined the rebar installation on Elevations 157’-10” + 6’-1” and 186’ + 5’, that was prepared for concrete pour, to ensure that the licensee had measured the reinforcing steel size, spacing, lap splice length, and concrete minimum protection coverage. The inspectors reviewed to determine whether the licensee performed inspection on installation, testing, and testing frequencies of swaged mechanical splices in accordance with the requirements of the design drawings, the American Concrete Institute (ACI) Codes, and the ASME Code Section III Division 2, Concrete Containment. The inspectors also examined the formwork installation and tendon sleeve condition.

Concrete Pour

The inspectors reviewed the concrete pre-placement inspection checklist including cleaning and debris removal prior to the concrete pour. The inspectors observed concrete placement activities on elevations 157’-10” + 6’-1” and 186’ + 5’ to verify that activities pertaining to concrete delivery time, flow distance, layer thickness and concrete consolidation or vibration conformed to industry standards established by the ACI Codes. Concrete batch tickets were examined to verify the material and quantity of each component for concrete mix, truck revolution limit, concrete placement time limit, and water amount added to the mix. The inspectors observed that concrete placement activities were continuously monitored by the licensee and contractor’s quality control personnel and engineers. The inspectors witnessed in-process testing and reviewed the results for slump, air content, temperature, unit weight, and molding of the concrete cylinders for compressive strength testing, and also witnessed sample points and truck loads to verify that concrete samples for the field testing and cylinders for the laboratory testing were obtained at the point of placement (end of chute line) and the middle portion of the truck loads. The inspectors reviewed concrete being poured into cylinders to determine whether it was molded in accordance with applicable American Society for Testing and Materials (ASTM) requirements of ASTM C 172, Standard Method of

Sampling Freshly Mixed Concrete, and to determine whether appropriate concrete field testing was performed by Quality Control (QC) inspectors.

The inspectors reviewed or examined the licensee activities to verify that the activities met the ACI code requirements, the licensee documents, and the industry standards. The inspectors examined the batch plant for its certification and the preparation of the concrete pour.

Document Review

The inspectors reviewed the Engineering Changes (ECs), specifications, drawings, work packages, NCRs, concrete compressive testing results, and documents related to the concrete construction activities. The inspectors reviewed EC 75219, Reactor Building Delamination Repair Phase 3 - Concrete Removal, Revision 17, and 75220, Reactor Building Delamination Repair Phase 4 - Concrete Placement, Revision 16. The inspectors reviewed SGT Work Packages (WP) 3-1732, Remove Containment Wall Concrete and 3-3732 A, B, C, and D Restoration of Containment Concrete Wall. The reviews or observations were conducted in order to verify that the licensee performed activities in accordance with the approved documents.

The inspectors reviewed records to verify that they met the licensee administrative control procedures, quality control, quality assurance program, and design and construction standards for the codes and industry.

The wall delamination repair efforts remained in progress at the end of this inspection period.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance and an associated non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion IX, “Control of Special Processes” for the licensee’s failure to establish measures to assure that testing of rebar splices would adhere to the requirements of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

Description: The licensee was in the process of conducting repairs to the containment building wall to address delaminated concrete that was identified when creating an opening for steam generator replacement in October 2009. Part of the repair included installation of rebar and connection of new rebar to existing rebar in the containment wall. The rebar installation preceded new concrete placement.

On August 4, 2010, the inspectors were reviewing the licensee’s testing of splices of the new rebar to old rebar. The inspectors identified that the licensee did not submit production splices for strength testing from a population of swaged mechanical splices where the licensee had completed concrete pours on the elevation below 176’ in bays 3 and 4. The inspectors reviewed the work records and determined that the licensee completed 67 swaged mechanical vertical splices and 27 vertical lap splices in the field for vertical rebar below elevation 176'. The licensee's engineering document, EC 75220, considered these to be straight bars. The licensee had used a sister splice test method and tested 30 swaged mechanical splices using this method.

The sister splice test method involved creating a second, or sister, splice in the field next to an actual production splice. The sister splices were created for the purposes of testing and were created in the same orientation and with the same equipment and process as the production splice. A quality control review was associated with each sister splice. The sister splices used rebar that had been earlier removed from the containment as part of creating the containment opening. After creation, the sister splices were sent to a laboratory for testing.

The production splice testing method involved taking an actual test sample from a population of installed splices, where the splice would have otherwise stayed in as part of the construction. Production splice test samples involve cutting the old rebar such that the test sample includes a portion of the old rebar, the splice, and the new rebar. Cutting the old rebar to produce a production splice sample shortens the remaining rebar. To facilitate a production splice, the old rebar must extend out of the concrete at a sufficient length to allow room for a new splice to be installed after the test sample is cut out.

The licensee used both lap splices and mechanical swaged splices to connect new rebar. A lap splice involves overlaying new rebar onto the existing rebar. Existing rebar in the containment included #8, #9, #10, and #11 sizes. Based on Progress Energy Drawing No. 421-358, Revision 0, the minimum lap length required for rebar #8, #9, #10, and #11 was 44", 49", 55", and 61", respectively. Table 1 of the same drawing showed that the minimum length of rebar required for the swaged mechanical splices extending from the concrete cut line was 9" for rebar #8, 10" for rebar #9 and #10, and 11" for rebar #11. The testing length required from the swaged mechanical splice was 4 feet total with 2 feet for each rebar from the center of the splice. The minimum length from the concrete cut line for an existing rebar #8 to produce a cutoff production splice for testing and making another splice in the field in the same rebar was 24" plus 9" which was a total of 33". The 33" was less than 44" required for one lap splice. In other words, any rebar meeting minimum length for a lap splice would also meet minimum length for a mechanical swaged splice with production testing.

The Attachment Z06 of EC 75220, Revision 16, Reactor Building Delamination Repair Phase 4 - Concrete Placement, only required sister splice testing for the planned swaged mechanical splices.

<u>Sister Splice Testing Schedule for Straight Rebars (Vertical Rebars)</u>

First 10 production splices	Test 3 sister splices
Next 90 production splices	Test 6 sister splices
Subsequent lots of 100 production	Test 4 sister splices

EC 75220 stated that the ASME Code Section III Division 2 Concrete Containment 2001 Edition with 2002 and 2003 Addenda was used for the design and construction of the containment wall repair. The requirements of Subsection CC-4333.5.3(a)(2)(a) Test Frequency of ASME Code 2003 Addenda were shown for production and sister splice testing requirements:

ASME Code Requirements for the Sample Frequency

If production and sister splices are tested, the sample frequency shall be as follows:

1 production splice of the first 10 production splices
1 production and 3 sister splices for the next 90 production splices
3 splices, either production or sister splices, for the next and each subsequent unit of 100 production splices

At least one-fourth of the total number of splices tested shall be production splices. The licensee had already installed and buried 67 vertical rebar swaged mechanical splices and 27 lap splices in the vertical direction with concrete pours below elevation 176' without submitted any production splices for the testing. It was clear that the licensee activities would not meet the ASME Code requirements.

The licensee stated in EC 75220 that Progress Energy could follow the D.C. Cook Nuclear Power Plant approved case to use 100 percent sister splice testing because the Crystal River Unit 3 had the same condition as D. C. Cook to meet a 10 CFR Part 50.54(a)(3) requirement. 10 CFR 50.54(a)(3)(ii) allows, in part, " the use of a quality assurance alternative or exception approved by an NRC safety evaluation, provided that the bases of the NRC approval are applicable to the licensee facility." D.C. Cook submitted a relief request to use 100 percent sister splices for testing and this was approved by NRC safety evaluation report because of insufficient rebar length and hardship involving removal of an additional to two feet of concrete to facilitate production splice testing.

However, Crystal River Unit 3 had 27 vertical rebars used for the lap splices. The inspectors noted that rebars meeting minimum requirements for lap splices also would meet minimum length to allow mechanical swage splices and production testing. The inspectors determined that these rebars provided an opportunity to perform swaged mechanical splice production testing. Each lap splice for rebar #8 was required to be 44" in the length as shown previously, which was more than the total length of 33" required for a production splice (24") to be cut off for the testing while leaving another splice (9") in the field with the same rebar for swaged mechanical splices. Similarly, rebars #9, #10, and #11 had longer lengths for potential production splice opportunities. The inspectors determined that the Crystal River Unit 3 could meet ASME Code requirements based on existing rebar lengths, and that the condition of D.C. Cook was not applicable to Crystal River Unit 3.

Analysis: The inspectors determined that the licensee's failure to facilitate production splice testing of mechanical splices to meet ASME Code requirements constituted a performance deficiency. The inspectors determined that the finding was more than minor because it was associated with the human performance attribute of the barrier systems cornerstone and affected the cornerstone objective of ensuring the reliability of containment wall barrier system. Failure to adhere to ASME Code testing requirements can adversely affect assurance that the rebar splices would meet strength requirements as part of the containment barrier.

The inspectors completed a Phase 1 screening of the finding using Inspection Manual Chapter 0609, “Significance Determination Process,” Attachment 4, “Phase 1 - Initial Screening and Characterization of Findings” and determined that the performance deficiency represented a finding of very low safety significance (Green). Specifically, the finding did not result in the actual loss of function of the Unit 3 Containment Wall.

This finding has a cross-cutting aspect in the area of Human Performance under the “Effectiveness Reviews” aspect of the “Decision-Making” component because the licensee failed to validate assumptions used as a basis for their decision to pursue an alternative testing plan. Specifically, the licensee assumed that rebar of sufficient length was not available at Crystal River to facilitate production testing. This assumption was used as the basis for adopting an alternative testing plan that was approved for D.C. Cook Nuclear Power Plant. The licensee’s review of their decision did not identify that Crystal River actually had rebar length available to facilitate production tests. This resulted in the possible unintended consequences of not meeting ASME Code requirements. [H.1(b)]

Enforcement: 10 CFR Part 50, Appendix B, Criterion IX, “Control of Special Processes” requires, in part, that measures shall be established to assure that special processes are controlled and accomplished in accordance with applicable codes. The licensee was performing a process of rebar splicing and testing in accordance with EC 75220, which referenced ASME Code 2001 Edition with 2002 and 2003 addenda. ASME Code 2001 Edition with 2002 and 2003 Addenda required production splice testing for swaged mechanical splices.

Contrary to the above, on August 4, 2010, the licensee did not ensure appropriate measures were established to ensure that ASME Code requirements would be met, in that EC 75220 established an alternative test process, which did not require production splice tests of mechanical swaged splices.

As part of their corrective actions, the licensee revised EC 75220 to require production splice testing for remaining rebar splice-work, such that ASME Code requirements would be met. Because this finding is of very low safety significance and has been entered into the licensee’s corrective action program as NCR 00415457, this violation is being treated as an NCV consistent with the NRC Enforcement Manual: NCV 05000302/2010004-03, Failure to Submit Production Splices of Swaged Mechanical Splices for the Testing.

4OA6 Exit

Exit Meeting Summary

On October 12, 2010, the resident inspectors presented the inspection results to Mr. J. Holt, Plant General Manager, and other members of licensee management. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
J. Holt, Plant General Manager
D. Douglas, Manager, Maintenance
S. Cahill, Manager, Engineering
J. Huegel, Manager, Nuclear Oversight
P. Dixon, Manager Training
C. Morris, Manager, Operations
D. Westcott, Supervisor, Licensing
B. Akins, Superintendent, Radiation Protection
C. Poliseno, Supervisor, Emergency Preparedness
I. Wilson, Manager Outage and Scheduling
J. Franke, Vice President, Crystal River Nuclear Plant
P. Fagan, Repair Design Engineering Supervisor
E. Avella, Manager, Containment Repair
D. Herrin, Licensing Engineer
S. Powell, Licensing Coordinator

NRC personnel:
D. Rich, Chief, Branch 3, Division of Reactor Projects

LIST OF ITEMS OPENED, CLOSED

Opened and Closed

05000302/2010004-01	NCV	Flood Calculations did not Reflect Plant Configuration (Section 1R06)
05000302/2010004-02	NCV	Inoperable Fire Barrier Penetration Seals (Section 4OA5.2)
05000302/2010004-03	NCV	Failure to Submit Production Splices of Swaged Mechanical Splices for the Testing (Section 4OA5.3)

Closed

05000302/2001003-01	URI	Degraded Fire/Flood Barriers (Section 4OA5.2)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Nuclear Condition Reports (NCRs)

NCR 280012, Abnormal reduction in CFT-1B Pressure
NCR 289957, Evaluate CFT-1B nitrogen addition rate
NCR 340156, CF-1-PI1 Needs rework
NCR 361692, When re-installing CFV-24 craftsman dropped fastener
NCR 281777, Loss of MCB Open indication for CFV-6
NCR 292431, CFV-28 Packing leak
NCR 304514, CFV-29 Approaching action time limit per SP-370 requirements

Section 1R05: Fire Protection

Procedures

AI-2205A, Pre Fire Plan – Control Complex
AI-2205B, Pre Fire Plan – Turbine Building
AI-2205C, Pre Fire Plan – Auxiliary Building
AI -2205F, Pre Fire Plan – Miscellaneous buildings and Components

Section 1R12: Maintenance Effectiveness

NCRs

NCR 363753, Multiple RM-A6 failure alarms
NCR 369447, RM-A2G tripped during breaker PM
NCR 369587, RM-A1 blew fuse
NCR 401152, RM-A6 failed low for 1.5 hours
NCR 389625, RMP-A2 tripped
NCR 372292, RM-A1(G) operating range failed low

Miscellaneous

SE10-0008, Maintenance Rule expert panel minutes making atmospheric radiation monitoring system MR a(1), dated February 10, 2010

Section 1R19: Post Maintenance Testing

Nuclear Condition Reports

NCR 415911, Possible oil in coolant for EGDG-1C
NCR 415750, Leak identified in EGDG-1C lube oil heat exchanger

Section 1R20: Refueling and Outage Activities

Procedures

AI-504, Guidelines for Cold Shutdown and Refueling
WCP-102, Outage Risk Management

Section 4OA2: Problem Identification and Resolution
NCR 362346, AHF-1A Tripped while running in slow speed
NCR 370660, AHF-1A Tripped while running in slow speed
NCR 379949, Trip of AHF-1A from low speed
NCR 395045, MRFFs not properly classified for trips of AHF-1A

Section 4OA5, Other Activities

Section 4OA5.2

Nuclear condition reports

NCR 266356
NCR 264494

Other

Crystal River Unit 3 Operating License
Fire Protection Plan, Revision 25
Fire Protection Plan, Revision 26
Updated Final Safety Analysis Report, Chapter 9
IMC 0609, App F, Fire Protection Significance Determination Process, dated 02/28/05,

Section 4OA5.3

Procedures

PT-0407C, Reactor Building Containment Tendon Detensioning, Retensioning, Replacements, Examinations. and Testing
Precision Surveillance Corporation (PSC) Procedure F & Q 8.1, RAM Tendon Detensioning, Revision 2
PSC Procedure 9.0, Monitor Tendon Force (Liftoff), Revision 0
PSC Procedure 10.0, Calibration of Measuring and Test Equipment, Revision 0
PSC Procedure 10.1, Verification of Calibration Status of Hydraulic Pressure Gauges, Revision 0
Mistras Project R10-215, CR3 Tendon Detensioning Monitoring Procedure, Revision 0

Other

Engineering Change (EC) 75218, Reactor Building Repair Phase 2 – Detensioning
Work Package (WP) 1710B, Tendon Detensioning
Tendon Detensioning Monitoring Communication Plan
CR3 Detension Strain Gauge Graphs and Logs
Acoustic Sound System Graphs and Records

EC 75219, Reactor Building Delamination Repair Phase 3 - Concrete Removal, Rev. 17
EC 75220, Reactor Building Delamination Repair Phase 4 - Concrete Placement, Revision 16.
WP 3-1732, SGT Remove Containment Wall Concrete
WPs 3-3732A, 3-3732B, 3-3732C, and 3-3732D, Restoration of Containment Concrete Wall.
Review of the 4" diameter of Core Bore sample from the drilling at Bay 3 and 4 and other bays for the vertical cracks.
NCR 00415457, Reinforcement Splices Test Plan Question Based on NRC
Certified Materials Test Reports for Compressive Strength for Concrete Sample Dated 7-6, 7-12, 7-17, 8-27, and 8-30-2010
WP 3732D, Horizontal Rebars Drawing, Atta. 9, Sheet 1 of 1
Certified Materials Test Report for Sister Splices on Various Rebar Grades such as Grade 40 Existing or 60 New.
Drawing 421-358, Containment Restoration Bar Reinforcement Splice Details