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

February 5, 2016

Mr. Mano Nazar
President and Chief Nuclear Officer
Nuclear Division
NextEra Energy
P.O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: ST. LUCIE PLANT - NRC INTEGRATED INSPECTION REPORT 05000335/2015004 AND 05000389/2015004

Dear Mr. Nazar:

On December 31, 2015, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your St. Lucie Plant (PSL) Units 1 and 2. The enclosed integrated inspection report documents the inspection results, which were discussed on January 14, 2016, with Mr. Costanzo and other members of your staff.

This report documents five NRC-identified findings of very low safety significance (Green). Four of these findings involved violations of NRC requirements and one of them was associated with a traditional enforcement Severity Level IV violation. Further, inspectors documented two licensee-identified violations which were determined to be of very low safety significance. Because of the very low safety significance, and because the issues were entered into your corrective action program (CAP), the NRC is treating these issues as Non-Cited Violations (NCVs) consistent with Section 2.3.2.a of the NRC Enforcement Policy.

If you contest the violation or significance of any NCV, 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 St. Lucie Power Plant.

If you disagree with a cross-cutting aspect assignment 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 St. Lucie Plant.

In accordance with Title10 of the Code of Federal Regulations 2.390 "Public inspections exemptions, requests for withholding," of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC's Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management 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/

LaDonna B. Suggs, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Docket Nos. 50-335, 50-389
License Nos. DPR-67, NPF-16

Enclosure:
IR 05000335/2015004, 05000389/2015004
w/Attachment: Supplementary Information

cc w/encl: (See next page)

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Letter to Mano Nazar from LaDonna B. Suggs dated February 5, 2016

SUBJECT: ST. LUCIE PLANT - NRC INTEGRATED INSPECTION REPORT 05000335/2015004 AND 05000389/2015004

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REGION II

Docket Nos:	50-335, 50-389
License Nos:	DPR-67, NPF-16
Report Nos:	05000335/2015004, 05000389/2015004
Licensee:	Florida Power & Light Company (FP&L)
Facility:	St. Lucie Plant, Units 1 & 2
Location:	6501 South Ocean Drive Jensen Beach, FL 34957
Dates:	October 1, 2015 to December 31, 2015
Inspectors:	T. Morrissey, Senior Resident Inspector J. Reyes, Resident Inspector P. Capehart, Senior Operations Engineer (Section 1R11.3) B. Collins, Reactor Inspector (Section 1R08) A. Sengupta, Reactor Inspector (Section 1R08) J. Rivera-Ortiz, Senior Reactor Inspector (Sections 1R15 and 4OA2.) D. Bacon, Senior Operations Engineer (Section 1R11.4) A. Goldau, Operations Engineer (Section 1R11.4)
Approved by:	LaDonna B. Suggs, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

SUMMARY

IR 05000335/2015004, 05000389/2015004; 10/01/2015 – 12/31/2015; St. Lucie Nuclear Plant (PSL), Units 1 & 2; Licensed Operator Requalification; and Identification and Resolution of Problems.

The report covered a three-month period of inspection by the resident inspectors and specialist inspectors from the Region II Office. Five findings of very low safety significance were identified by the inspectors. Four of the findings were considered Non-Cited Violations (NCVs) of NRC requirements and one of the NCVs was associated with a traditional enforcement Severity Level IV violation. The significance of inspection findings are indicated by their color (i.e., greater than Green, or Green, White, Yellow, or Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," (SDP) dated April 29, 2015. The cross-cutting aspects were determined using IMC 0310, "Aspects Within the Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements were dispositioned in accordance with the NRC's Enforcement Policy dated February 4, 2015. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 5.

<u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Initiating Events

- Green: An NRC-identified, Non-cited Violation of 10 CFR Appendix B, Criterion III, "Design Control," was identified for the failure to verify the adequacy of the Unit 1 and Unit 2 replacement steam generators (RSGs) design with respect to the requirements in the American Society of Mechanical Engineers Boiler Pressure Vessel Code (ASME Code), Section III, Article NB-3000, for the primary stress and fatigue analyses of the pressure-retaining tube-to-tubesheet welds. The licensee entered the issue in the corrective action program, and performed the required analyses for the Unit 1 and Unit 2 RSGs to demonstrate that the design met the ASME Code requirements.

  The inspectors used the guidance in NRC Inspector Manual Chapter (IMC) 0612, Appendix B, "Issue Screening," and determined that the performance deficiency was more-than-minor because it was associated with the design control attribute of the Initiating Events Cornerstone, and adversely affected the cornerstone objective. Specifically, the failure to verify that the required stress and fatigue analyses were performed in accordance with the ASME Code did not support the objective of limiting the likelihood of primary-to-secondary leakage events that could upset plant stability and challenge critical safety functions during shutdown, as well as power operations. The inspectors evaluated this finding using NRC IMC 0609, Appendix A, Significance Determination Process for Findings At-Power, Exhibit 1 – Initiating Events Screening Questions. The finding screened as Green because the stress calculations demonstrated that there was no degraded steam generator (SG) tube condition where one tube could not sustain three times the differential pressure across a tube during normal full power, and none of the SGs violated the "accident leakage" performance criterion. Additionally, the stress calculations demonstrated that the finding did not result in a condition that exceeded the reactor coolant system leak rate for a small loss of coolant accident (LOCA), or affected other systems used to mitigate a LOCA resulting in a total loss of their function (e.g., Interfacing System LOCA). The inspectors determined that no cross-cutting aspect was associated with this finding because the performance deficiency occurred more than 3 years ago, and it was not reflective of present performance. (Section 4OA2)

Cornerstone: Mitigating Systems

- Green: An NRC-identified finding related to 10 CFR 55.59, “Requalification,” was identified based on a determination that greater than 20 percent of the 2014 biennial written exam question sampled for review were flawed. The finding did not involve a violation of NRC requirements.

  The inspectors determined that the finding was more than minor because it was associated with the Human Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding adversely affected the quality and level of difficulty of biennial written examinations, which potentially impacted the facility’s ability to appropriately evaluate licensed operators. The risk importance of this issue was evaluated using IMC 0609, Appendix I, “Licensed Operator Requalification Significance Determination Process (SDP).”

  The qualitative standards used by the inspectors were defined in TR-AA-220-1004, Licensed Operator Continuing Training Annual Operating and Biennial Written Exams. Because more than 20 percent, but less than 40 percent, of the questions reviewed were flawed, Blocks 4 and 5 of Appendix I characterized the finding as having very low safety significance (Green). A review of the cross-cutting aspects was performed and no associated cross-cutting aspect was identified. (Section 1R11)

- Severity Level IV: An NRC-identified severity level IV (SLIV) NCV of 10 CFR 55.49, “Integrity of examinations and tests“ was identified based on a determination that a non-willful compromise of a remedial examination required by 10 CFR 55.59 affected the equitable and consistent administration of the examination. An associated finding of very low safety significance (Green) was also identified based on a determination that a biennial written remedial examination was not prepared and approved in accordance with licensee procedures.

  The licensee’s failure to develop and administer a remedial examination in accordance with TR-AA-220-1004, Licensed Operator Continuing Training Annual Operating and Biennial Written Exams, was a performance deficiency. The performance deficiency was determined to be more than minor because it was associated with the Human Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the performance deficiency caused an incident of exam compromise that affected the equitable and consistent administration of the exam and resulted in a licensed operator being authorized to resume licensed duties prior to the condition being corrected. Additionally, the finding adversely affected the integrity of a biennial written remedial examination, which impacted the facility’s ability to appropriately evaluate a licensed operator. The licensed operator subsequently passed another remedial examination that was one hundred percent different from his original exam and the previous remedial exam. The operator also demonstrated satisfactory performance while performing licensed operator duties and participating in the licensed operator requalification program.

The traditional enforcement violation was evaluated using the NRC Enforcement Policy dated January 28, 2013, and revised February 4, 2015. The inspectors determined the violation was SLIV per Section 6.1.d.2 because the associated finding was evaluated by the SDP as having very low safety significance (i.e., Green). The finding was directly related to the cross-cutting aspect of procedure adherence of the cross-cutting area of Human Performance because the training staff did not follow applicable guidance for the preparation and approval of licensed operator biennial written remedial examinations. [H.8] (Section 1R11)

- Green: An NRC-identified NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified for the licensee's failure to implement corrective actions to prevent fouling of the 2B component cooling water (CCW) heat exchanger (HX) that resulted in the number of blocked tubes exceeding the HX's maximum analyzed limit for plugged tubes. The licensee's failure to implement adequate corrective actions was a performance deficiency and was within the licensee's ability to prevent. Corrective actions included installing temporary equipment to ensure adequate continuous sodium hypochlorite (SH) is injected through the CCW HXs to prevent biological fouling. The licensee entered this issue into the CAP.

  The performance deficiency was more-than-minor because if left uncorrected, the performance deficiency had the potential to lead to a more significant safety concern. Specifically, inadequate SH injection may cause extensive fouling and can lead to a common mode failure of the CCW HXs preventing the required cooling of safety-related structures, systems, and components (SSCs) analyzed heat loads during a design basis accident (DBA). Using Manual Chapter 0609.04, "Significance Determination Process Initial Characterization of Findings," Table 2 dated June 19, 2012, the finding was determined to affect the Mitigating Systems Cornerstone. Manual Chapter 0609 Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2 "Mitigating Systems Screening Questions," dated, June 19, 2012, was used to further evaluate this finding. The finding screened as Green because the finding did not represent either an actual loss of function of at least a single train for greater than its Technical Specification (TS) Allowed Outage Time, or two separate safety systems out-of-service (OOS) for greater than its TS Allowed Outage Time. The finding involved the cross-cutting area of the resolution component in Problem Identification and Resolution (PI&R) because the organization did not take effective corrective actions to address issues in a timely manner commensurate with the safety significance of the CCW HX, in that, even after the repeat fouling issue had been identified on the 2B CCW HX, the immediate resolution of inadequate SH injection remained unresolved until the inspectors addressed this issue with plant management [P.3] (Section 4OA2.3).

- Green: An NRC-identified NCV of TS 6.8.1, "Procedures and Programs," was identified for the licensee's failure to properly implement written procedures covering activities referenced in NRC Regulatory Guide 1.33, Revision 2, dated February 1978. Specifically, the licensee routinely failed to complete engineering evaluations to determine the acceptability of scaffolds that did not meet the 2 inch clearance requirement of NextEra Nuclear Fleet Administrative Procedure MA-AA-100-1002, "Scaffold Installation, Modification, and Removal Requests." The licensee's failure to erect scaffold in compliance with the NextEra Nuclear Fleet Administrative Procedure was a performance deficiency. This issue has been entered into the licensee's CAP.

The performance deficiency was more-than-minor because it was associated with the Mitigating Systems Cornerstone Attribute of Protection against External Factors, Seismic, and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, routinely failing to complete engineering evaluations of scaffold clearance issues could lead to the continued use of inadequately installed scaffolds, ultimately posing a risk of rendering safety-related equipment inoperable during normal and adverse conditions, such as a design basis seismic event. Using Inspection Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," Table 2, "Cornerstones Affected by Degraded Condition or Programmatic Weakness," dated June 19, 2012, the inspectors determined the finding affected the Mitigating Systems Cornerstone. Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," dated June 19, 2012, was used to further evaluate this finding. The finding screened as Green because 'no' was answered to all four screening questions, i.e. the finding did not represent an actual loss of function of any piece of plant equipment for any amount of time. The finding involved the cross-cutting area of PI&R in the aspect of resolution, in that the organization did not take effective corrective actions to address the scaffolding issues in a timely manner, as evidenced by a period of five months in which the inspectors continued to identify non-conformances with erected scaffold [P.3] (Section 4OA2.4).

Licensee-Identified Violations

Two violations of very low safety significance (Green), which were identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and the associated corrective action tracking number is listed in section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent rated thermal power (RTP). On December 4, 2015, power was lowered to 92 percent RTP due to a high differential pressure across a debris filter associated with the circulating water system. The unit was returned to 100 percent on December 5, 2015. On December 21, 2015, one control element assembly (CEA) lost power and dropped into the core. Reactor power was lowered to 69 percent. After repairs, the CEA was restored to its group position. Reactor power was restored to 100 percent RTP on December 22, 2015. The unit was at 100 percent power for the remainder of the inspection period.

Unit 2 began the inspection period with the reactor defueled. On October 25, 2015, the unit was restarted and reached 100 percent RTP on October 28, 2015. On November 25, 2015, power was reduced to 92 percent to repair leaking tubes in the 2A2 condenser water box. Repairs were completed and the Unit returned to 100 percent power November 28, 2015. The unit was at 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity (R)

1R01 Adverse Weather Protection

Seasonal Winter Weather Conditions

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the station's cold weather preparations as described in procedure OP-AA-102-1002, "Seasonal Readiness". The inspectors verified the cold weather seasonal preparations were completed as specified by the procedure. Action requests (ARs) were checked to ensure that the licensee was identifying and resolving weather-related issues and that corrective actions from the previous cold weather season had been satisfactorily resolved. The inspectors performed a walkdown of the following safety-related equipment on both units that are exposed to the outside weather conditions to identify any potential adverse conditions. This inspection constitutes one sample.

- Unit 1 and Unit 2 emergency diesel generator (EDG) rooms
- Unit 1 and Unit 2 main feedwater isolation valve (MFIV) areas
- Unit 1 and Unit 2 auxiliary feedwater (AFW) pump areas
- Unit 1 and Unit 2 refueling water tank (RWT) areas

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial Equipment Walkdowns

a. Inspection Scope

The inspectors conducted partial alignment verifications of the safety-related systems listed below. These inspections included reviews using plant lineup procedures, operating procedures, and piping and instrumentation drawings, which were compared with observed equipment configurations to verify that the critical portions of the systems were correctly aligned to support operability. The inspectors also verified that the licensee had identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers, and that the issues were documented in the licensee's CAP. This inspection constitutes three samples. Documents reviewed are listed in the Attachment.

- Unit 2 2A EDG after returning to service from installation of voltage regulator modification and post maintenance testing
- Unit 2 AFW system, A, B, and C pumps after post maintenance testing and placing the system in standby alignment prior to MODE 3 greater than 1,750 psia RCS pressure
- Unit 1 1A EDG while 1B EDG was removed from service for planned maintenance

b. Findings

No findings were identified.

.2 Complete System Walkdown

a. Inspection Scope

The inspectors conducted a detailed walkdown and review of the alignment and condition of the Unit 2 CCW system to verify its capability to meet its design basis function. The inspectors utilized the licensee procedures listed in the Attachment, as well as other licensing and design documents, to verify the system alignment was correct. During the walkdown, the inspectors verified that:

- Valves were correctly positioned and did not exhibit leakage that would impact their function
- Electrical power was available as required
- Major portions of the system and components were correctly labeled, cooled, and ventilated
- Hangers and supports were correctly installed and functional
- Essential support systems were operational
- Ancillary equipment or debris did not interfere with system performance
- Tagging clearances were appropriate
- Valves were locked as required by the licensee's locked valve program

Pending design and equipment issues were reviewed to determine if the identified deficiencies significantly impacted the system's functions. Items included in this review were the operator workaround list, the temporary modification list, system health reports, system description, and outstanding maintenance work requests/work orders (WOs). In addition, the inspectors reviewed the licensee's CAP to ensure that the licensee was identifying and resolving equipment alignment problems. This inspection constitutes one sample.

b. Findings

No findings were identified.

1R05 Fire Protection

Fire Area Walkdowns

a. Inspection Scope

The inspectors toured the following plant areas during this inspection period to evaluate conditions related to control of transient combustibles, ignition sources, and the material condition and operational status of fire protection systems, including fire barriers used to prevent fire damage or fire propagation. The inspectors reviewed these activities against provisions in the licensee's administrative procedure 1800022, "Fire Protection Plan," and 10 CFR Part 50, Appendix R. The licensee's fire impairment lists, updated on an as-needed basis, were routinely reviewed. In addition, the inspectors reviewed the CAP database to verify that fire protection problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment. This inspection constitutes five samples. The following areas were inspected:

- Unit 1 A and B safety-related battery rooms and alternate shutdown panel
- Unit 1 1A EDG room
- Unit 2 reactor containment building (RCB)
- Unit 2 CCW surge tank room
- Unit 2 Boric acid (BA) condensate tanks, condensate and holding pump rooms

b. Findings

No findings were identified.

1R08 In-service Inspection Activities

a. Inspection Scope

Non-Destructive Examination Activities and Welding Activities

From September 14, 2015, through October 2, 2015, inspectors conducted an onsite review of the implementation of the licensee's in-service inspection (ISI) program for monitoring degradation of the RCS boundary, risk-significant piping and component boundaries, and containment boundaries in Unit 2.

The inspectors either directly observed or reviewed the following non-destructive examinations (NDEs), mandated by the ASME BPVC (Code of Record: 2004 Edition) to evaluate compliance with the ASME Code, Section XI and Section V requirements, and if any indications or defects were detected, to evaluate if they were dispositioned in accordance with the ASME Code or an NRC-approved alternative requirement. The code of record for the containment program is the 2001 Edition with 2003 Addenda. The inspectors also reviewed the qualifications of the NDE technicians performing the examinations to determine whether they were current and in compliance with the ASME Code requirements.

- WO 40202242, Ultrasonic Testing (UT), Pressurizer Zone 2-005 Class 1 (reviewed)
- WO 40202526, UT, Loop 2B Shutdown Cooling Line, Class 2 (reviewed)
- WO 40302491, Visual Testing (VT-3) IWE Moisture Barrier General Visual (observed)
- WO 40299600-02, Penetrant Testing (PT), Seal Weld #02021, Component SE-03-2B (reviewed)
- WO 37020197-09, VT-3, Rigid Frame Support CW-3000-77, Circulating Water from Intake Cooling Water (ICW) Pump
- WO 40202242, Magnetic Testing (MT), Pressurizer Zone 2-005/02-005A (reviewed)
- Report #CSI-FAC-PSL-2-22-P, Component #14C83-P-28-60, UT, Heater Drain Back to Condensate System (reviewed)

The inspectors either directly observed or reviewed the following welding activities, qualification records, and associated documents, in order to evaluate compliance with procedures, and the ASME Code, Section XI and Section IX requirements. Specifically, the inspectors reviewed the WO, repair and replacement plan, weld data sheets, welding procedures, procedure qualification records, welder performance qualification records, and NDE reports.

- WO 40298308 01, Vent Valve V3922 for Safety Injection Tank 2A1 outlet, Class 1 (reviewed)
- WO 40299600 02, Seal Weld of Safety Injection Valve, Class 2 (reviewed)
- WO 40079220 07, Thermowell for TE-1122HD (reviewed)

During non-destructive surface and volumetric examinations performed since the previous refueling outage (RFO), the licensee did not identify any relevant indications that were analytically evaluated and accepted for continued service; therefore, no NRC review was completed for this inspection procedure (IP) attribute.

<u>Pressurized Water Reactor Vessel Upper Head Penetration Inspection Activities</u>

The inspectors verified that for the Unit 2 vessel head, a bare metal visual examination and a volumetric examination were not required during this outage, in accordance with the requirements of ASME Code Case N-729-1 and 10 CFR 50.55a(g)(6)(ii)(D).

The licensee did not identify any relevant indications that were accepted for continued service. Additionally, the licensee did not perform any welding repairs to the vessel head penetrations since the beginning of the last Unit 2 RFO; therefore, no NRC review was completed for these IP attributes.

Boric Acid Corrosion Control Inspection Activities

The inspectors reviewed the licensee's boric acid corrosion control (BACC) program activities to determine if the activities were implemented in accordance with the commitments made in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," and applicable industry guidance documents. Specifically, the inspectors performed an onsite records review of procedures, and the results of the licensee's containment walkdown inspections performed during the current RFO. The inspectors also interviewed the BACC program owner, conducted an independent walkdown of containment to evaluate compliance with licensee BACC program requirements, and verified that degraded or non-conforming conditions such as BA leaks, were properly identified and corrected in accordance with the licensee's BACC and CAP.

The inspectors reviewed the following engineering evaluations completed for evidence of BA leakage to determine if the licensee properly applied applicable corrosion rates to the affected components, and properly assessed the effects of corrosion-induced wastage on structural or pressure boundary integrity, in accordance with the licensee's procedures.

- AR 1972587-01, BA Leak of <1 dpm was observed at Unit 2 V2464 Packing Gland
- AR 2049447-01, BA Leak of <1 dpm was observed at Unit 2 V3664 Packing Gland
- AR 20081111-01, BA Leak of <1 dpm was observed at Unit 2 V2147 Packing Gland

The inspectors reviewed the following condition reports (CRs) and associated corrective actions related to evidence of BA leakage to evaluate if the corrective actions completed were consistent with the requirements of the ASME Code and 10 CFR Part 50, Appendix B, Criterion XVI.

- 1908552, 2013 BAC SAAFI Fleet BACC Training for Manager
- 1983808, V3461 Active BA Seat Leak
- 2013791, V6184 Active BA Bonnet Leak
- 1972693, V2595 Active BA Bonnet Leak
- 2068416, V2343 Active BA Leak at Packing
- 2075128, V1475 Active BA Leak at Inlet Package
- 2075125, V1474 Active BA Leak at Inlet Package

Steam Generator Tube Inspection Activities

The inspectors reviewed the eddy current test (ECT) activities performed in Unit 2 SGs A and B during this current RFO to verify compliance with the licensee's TSs, ASME BPVC Section XI, and Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines."

The inspectors reviewed the scope of the ECT examinations and the implementation of scope expansion criteria to verify these were consistent with the Electric Power Research Institute (EPRI) Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 7. The inspectors reviewed documentation for a sample of ECT data analysts, probes, and testers to verify that personnel and equipment were qualified to detect the applicable degradation mechanisms in accordance with the EPRI

Examination Guidelines. This review included a sample of site-specific Examination Technique Specification Sheets (ETSSs) to verify that their qualification and site-specific implementation were consistent with Appendix H or I of the EPRI Examination Guidelines. The inspectors also reviewed a sample of ECT data for SG tubes A-R86C85, A-R92C81, A-R135C78, B-R114C67, and B-R115C86, with a qualified data analyst, to confirm that data analysis and equipment configuration were performed in accordance with the applicable ETSSs and site-specific analysis guidelines. The inspectors verified that recordable indications were detected and sized in accordance with vendor procedures.

The inspectors selected a sample of degradation mechanisms from the Unit 2 Degradation Assessment report (i.e., anti-vibration bar wear, wear at V-shaped support pads, and wear at the broached tube support plates in straight sections) and verified that their respective in-situ pressure testing criteria were determined in accordance with the EPRI Steam Generator Integrity Assessment Guidelines, Revision 3. Additionally, the inspectors reviewed ECT indication reports to determine whether tubes with relevant indications were appropriately screened for in-situ pressure testing. The inspectors also compared the latest ECT examination results with the last Condition Monitoring and Operational Assessment report for Unit 2 to assess the licensee's prediction capability for maximum tube degradation and number of tubes with indications. The inspectors verified that the licensee's evaluation was conservative, and that current examination results were bound by the Operational Assessment projections.

The inspectors assessed the latest ECT examination results to verify that new degradation mechanisms, if any, were identified and evaluated before plant startup. The review of ECT examination results included the disposition of potential loose part indications on the SG secondary side, to verify that corrective actions for evaluating and retrieving loose parts were consistent with the EPRI Guidelines. The inspectors also reviewed a sample of primary-to-secondary leakage data for Unit 2 to confirm that operational leakage in each SG remained below the detection or action level threshold during the previous operating cycle.

The inspectors' review included the implementation of tube repair criteria and repair methods to verify they were consistent with plant TSs and industry guidelines. The inspectors verified that the licensee had selected the appropriate tubes for plugging based on the required plugging criteria. The inspectors reviewed the tube plugging procedure and a sample of tube plugging results for tubes A-R86C85, B-R114C67, and B-R115C86 to determine if the licensee installed the tube plugs in accordance with the applicable procedures.

The inspectors also interviewed licensee staff and reviewed a sample of inspection results for the inspection conducted in the secondary side internals of SGs A and B to verify that potential areas of degradation based on site-specific operating experience (OE) were inspected and appropriate corrective actions were taken to address degradation indications. This review included an evaluation for a potential loose part in the secondary side of SG A.

Additionally, the inspectors reviewed documentation and interviewed licensee staff regarding evaluations and corrective actions for the event(s) which led to the deformation of the SG B feed ring and its associated supports.

Identification and Resolution of Problems

The inspectors reviewed a sample of ISI-related issues entered into the CAP to determine if the licensee had appropriately described the scope of the problem, and had initiated corrective actions. The review also included the licensee's consideration and assessment of OE events applicable to the plant. The inspectors performed this review to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program and Licensed Operator Performance

.1 Resident Inspector Quarterly Review

a. Inspection Scope

On November 2, 2015 the inspectors observed and assessed an evaluated simulator scenario during continuing training on the control room simulator. The simulated scenarios included a SG tube rupture with failure of a high pressure safety injection (HPSI) pump to start and a manual reactor trip. The scenario included an Alert classification and a notification to the State due to a potential loss of the RCS barrier. Documents reviewed are listed in the Attachment. The inspectors also reviewed simulator physical fidelity and specifically evaluated the following attributes related to the operating crew's 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 TS actions, regulatory reporting requirements, and emergency plan classification and notification
- Crew overall performance and interactions
- Effectiveness of the post-evaluation critique

This inspection completes one sample under this IP.

b. Findings

No findings were identified.

.2 Control Room Observations

a. Inspection Scope

The inspectors observed and assessed licensed operator performance in the plant and main control room, particularly during periods of heightened activity or risk and where the activities could affect plant safety. Documents reviewed are listed in the Attachment. Specifically, the inspectors observed activities in the control room during the following two evolutions:

- November 25, 2015 Unit 2 emergent rapid down-power to 92 percent RTP in preparations to make repairs to the 2A2 water box due to increased sodium
- December 21, 2015 Unit 1 emergent rapid down-power to 69 percent RTP due to a dropped CEA

The inspectors focused on the following conduct of operations attributes, as appropriate:

- Operator compliance and use of procedures
- Control board manipulations
- Communication between crew members
- Use and interpretation of plant instruments, indications and alarms
- Use of human error prevention techniques
- Documentation of activities, including initials and sign-offs in procedures
- Supervision of activities, including risk and reactivity management

This inspection constitutes two inspection samples.

b. Findings

No findings were identified.

.3 Annual Review of Licensee Requalification Examination Results

a. Inspection Scope

On December 1, 2015, the licensee completed the annual requalification operating examinations required to be administered 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 individual operating examinations and the crew simulator operating examinations in accordance with IP 71111.11, "Licensed Operator Requalification Program." These results were compared to the thresholds established in Section 3.02, "Requalification Examination Results," of IP 71111.11.

b. Findings

No findings were identified.

.4 Licensed Operator Requalification

a. Inspection Scope

The inspectors reviewed the facility operating history and associated documents in preparation for this inspection. During the week of November 16, 2015, the inspectors reviewed documentation, interviewed licensee personnel, and observed the administration of operating tests associated with the licensee's operator requalification program. Each of the activities performed by the inspectors was done to assess the effectiveness of the facility licensee in implementing requalification requirements identified in 10 CFR Part 55, "Operators' Licenses." The evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG-1021, "Operator Licensing Examination Standards for Power Reactors," and IP 71111.11, "Licensed Operator Requalification Program." The inspectors also evaluated the licensee's simulation facility for its adequacy of use for operator licensing examinations using ANSI/ANS-3.5-1998, "American National Standard for Nuclear Power Plant Simulators for use in Operator Training and Examination." The inspectors observed two crews during the performance of the operating tests. Documentation reviewed included: written examinations; Job Performance Measures (JPMs); simulator scenarios; licensee procedures; on-shift records; simulator modification request records; simulator performance test records; operator feedback records; licensed operator qualification records; remediation plans; watch standing records, and; medical records. The records were inspected using the criteria listed in IP 71111.11. Documents reviewed during the inspection are documented in the List of Documents Reviewed.

b. Findings

.1 Written NRC Biennial Examinations Did Not Meet Qualitative Standards

Introduction: The inspectors identified a finding of very low safety significance (Green) associated with 10 CFR 55.59, "Requalification," based on a determination that between 20 and 40 percent of the written examination questions administered to licensed operators during the biennial requalification examination were flawed.

Description: The NRC-required biennial written examinations are designed to ensure that licensed operators maintain safe standards of knowledge and ability in order to take appropriate safety-related actions in response to actual abnormal or emergency conditions. As part of the biennial licensed operator training inspection, the inspectors evaluated the content of two NRC-required biennial written examinations (SRO and RO Written Examinations 082014EA and 082014EB), that the licensee developed and administered to licensed operators in 2014. The standards for determining whether a question is flawed are located in TR-AA-220-1004, "Licensed Operator Continuing Training Annual Operating and Biennial Written Exams."

Item 5 in Section 4.4.3, "Exam Development," of TR-AA-220-1004 stated, in part, "Direct look-up questions shall NOT be used on LOCT Biennial Comprehensive Written Exams." Additionally, Item 7 in Section 2.0, "Terms and Definitions," of TR-AA-220-1004 defined a Direct Look-up question as, "one in which the answer can be directly found in a reference without any analysis, synthesis or application of information."

Item 7 in Section 2.1, “Test Item Characteristics,” of Attachment 2, “Biennial Comprehensive Written Exam Validation Briefing/Checklist,” in TR-AA-220-1004 asks, in part, “Are the distractors (i.e., non-correct ‘answers’) plausible? For example, if an incorrect assumption was made by the examinee, could he/she come to the answers given?”

The inspectors reviewed 70 test questions, which comprised two examinations (SRO and RO Written Examinations 082014EA and 082014EB). Nineteen of the 70 questions (approximately 27 percent) were determined to contain the following types of flaws:

- Direct Lookup: 11 test questions
- Two or more non-plausible distractors: 11 test questions

Three of the questions contained both of the flaws listed above. Collectively, these flaws adversely affected the ability to discriminate between an Operator who possessed a satisfactory level of safety significant knowledge and an Operator who did not. The licensee entered the issue into their CAP as CR # 02067887.

Analysis: The inspectors determined that the failure to ensure that biennial written examinations met the qualitative industry and site standards established for written examinations, specifically defined in TR-AA-220-1004, was a performance deficiency. The inspectors determined that the performance deficiency was more than minor in accordance with IMC 0612, Appendix B, “Issue Screening,” because it was associated with the Human Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective in that the quality of biennial written examinations potentially impacted the licensee’s ability to appropriately evaluate licensed operators. The significance of the finding was evaluated using IMC 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP).” Blocks 4 and 5 of IMC 609, Appendix I, resulted in a finding of very low safety significance (Green) because between 20 and 40 percent of the questions reviewed did not meet the standard. No cross- cutting aspect was identified that would be considered a contributor to the cause of the finding.

Enforcement: 10 CFR 55.59, “Requalification,” Section 4, “Evaluation,” requires in part, that the requalification program must include written examinations which determine licensed operators’ and senior operators’ knowledge of subjects covered in the requalification program, and provide a basis for evaluating their knowledge of abnormal and emergency procedures. However, the regulation does not specify a requirement for the quality of examination material; therefore, no violation of regulatory requirements occurred. Enforcement action does not apply because the performance deficiency did not involve a violation of a regulatory requirement. Because this finding does not involve a violation of regulatory requirements and has very low safety significance, it was identified as a FIN 05000335,389/2015004-01, NRC Biennial Written Examinations Did Not Meet Qualitative Standards.

.2 NRC Biennial Remedial Written Examination Contained Exact Duplicate Question with a Non-willful Compromise of a Remedial Examination Required by 10 CFR 55.59 Which Affected the Equitable and Consistent Administration of the Exam

<u>Introduction</u>: The NRC-identified SLIV NCV of 10 CFR 55.49, "Integrity of examinations and tests," was identified based on the licensee's failure to develop and administer a remedial examination in accordance with TR-AA-220-1004, Licensed Operator Continuing Training Annual Operating and Biennial Written Exams, which caused an incident of exam compromise that affected the equitable and consistent administration of the exam and resulted in a licensed operator being authorized to resume licensed duties prior to the condition being corrected. A Green finding was identified for the same performance deficiency involving remedial exam integrity. The risk importance of this issue, related to exam integrity, was determined to be of very low safety significance (Green).

<u>Description</u>: On December 12, 2014, a licensed operator was administered a remedial examination that did not meet the requirements in licensee procedure TR-AA-220-1004, Licensed Operator Continuing Training Annual Operating and Biennial Written Exams, and TR-AA-230-1003-F13, Written/Oral Examination Key Cover Sheet. The exam contained one question which was an exact duplicate of a question that was on the initial biennial comprehensive written examination, which the operator had failed, leading to the remedial exam.

The operator received the minimum passing score (80%) on the remedial examination and had correctly answered the duplicated question. Removal of the repeated question from the remedial biennial written exam is an appropriate action that caused the operator to actually fail the exam. Since, the operator did not pass the examination, the required licensee training program was not completed, and the condition of the operators' license were not met. Because the error was not detected, the operator was allowed to resume all licensed operator duties and remained on-shift from December 2014 to August 2015.

On August 18, 2015, the licensee identified that the violation had occurred while performing a focused self-assessment in preparation for a NRC biennial licensed operator requalification program inspection. The licensee subsequently removed the individual from licensed operator duties, evaluated his performance on licensed operator continuing training simulator scenarios and program exams, and administered an appropriate remedial examination. The individual received a passing grade on the second remedial examination and was again returned to licensed operator duties. This issue was entered in the licensee's corrective action program as CR 02067887. The enforcement aspect was discuss in section 4OA7.

Because the operator was returned to licensed duties for approximately eight months before the problem was discovered, there was an actual effect on the equitable and consistent administration of an examination required by 10 CFR 55.59, "Requalification." The inspectors determined that the licensee's Apparent Cause Evaluation (ACE) for CR #02067887 failed to identify that neither of the two remedial examinations given to two licensed operators (exams 082014ED and 082014ES) were verified to meet the requirements of TR-AA-230-1003-F13, Written/Oral Examination Key Cover Sheet, which defines the requirements to declare an exam as a remedial exam. Additionally, the inspectors determined that TR-AA-230-1003-F13 for exam 082014EA was submitted, reviewed, and approved without any box checked "Yes" to indicate the type of exam that it was and that the exam procedure was not followed.

<u>Analysis</u>: On December 12, 2014, a licensed operator was administered a remedial examination that contained one question that was an exact duplicate of a question that was on the initial biennial comprehensive written examination that the operator failed. This was determined to be the performance deficiency.

Licensee procedure TR-AA-220-1004, Licensed Operator Continuing Training Annual Operating and Biennial Written Exams, section 4.4.3.4 states, in part, "Remedial exams should be developed as required in accordance with TR-AA-230-1004, SAT Implementation. No questions are to be repeated from the original examination without significant modification."

Section 4.6.5 of licensee procedure TR-AA-230-1004 states, "A remedial/make-up exam must differ from the failed exam by at least 90%, have the same number of test questions as the failed exam, focus on those areas noted as weaknesses, and include test questions on the content failed on previous exam, as well as areas that the student previously passed."

Section 4.6.5.A of licensee procedure TR-AA-230-1004 states, "Licensed Operator Continuing Training annual operating and biennial comprehensive remediation exams must have NO repeat questions, per TR-AA-220-1004, Licensed Operator Continuing Training Annual Operating and Biennial Written Exams."

A check box is contained within TR-AA-230-1003-F13, Written/Oral Examination Key Cover Sheet, for a remediation exam that states, in part, "For LOCT annual operating and biennial comprehensive remedial exams, verified no repeat questions."

It is stated in 10 CFR 55.49 that, "Applicants, licensees, and facility licensees shall not engage in any activity that compromises the integrity of any application, test, or examination required by this part. The integrity of a test or examination is considered compromised if any activity, regardless of intent, affected, or, but for detection, would have affected the equitable and consistent administration of the test or examination. This includes activities related to the preparation and certification of license applications and all activities related to the preparation, administration, and grading of the tests and examinations required by this part."

Remedial Training and Re-Examination was evaluated in accordance with IP 71111.11 Appendix F, "Remedial Training and Re-Examination Checklist." A licensed operator was administered a remedial exam that contained one question that was exactly duplicated from the original failed examination. This was a performance deficiency against the expected standards of integrity associated with licensed operator examinations required by 10 CFR 55.59(a)(2).

Requalification Examination Security was evaluated in accordance with IP 71111.11 Appendix E, "Requalification Examination Security Checklist." A licensed operator gained an unfair advantage on an examination required by 10 CFR 55.59, and this condition was not corrected prior to being authorized to resume licensed duties. Because the licensed operator received the minimum passing grade (80%) on a remedial examination that contained an exact duplicate of a question that was on the failed exam <u>and</u> was returned to licensed duties for approximately eight months before the problem was discovered, there was an actual effect on the equitable and consistent administration of an examination required by 10 CFR 55.59. A performance deficiency against the expected standards for examination integrity was considered a finding.

The inspectors determined that the performance deficiency was more than minor in accordance with IMC 0612, Appendix B, “Issue Screening,” because it was associated with the Human Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding affected the integrity of the biennial written remedial examinations, which impacted the facility’s ability to appropriately evaluate licensed operators.

The performance deficiency is a finding that was evaluated using the SDP in accordance with IMC 0609 Appendix I, “Licensed Operator Significance Determination Process.” This finding was determined to be Green.

The SDP finding was directly related to the cross-cutting aspect of procedure adherence of the cross-cutting area of Human Performance because the training staff did not follow applicable guidance for the preparation and approval of licensed operator biennial written remedial examinations. [H.8]

The SDP, however, does not specifically consider actual consequences, for example the individual was allowed to operate the plant without meeting the conditions of their operating license. Thus, although related to a common regulatory concern, it is necessary to address the finding and violation using different processes to correctly reflect both the safety significance of the associated finding and the regulatory impact of the violation.

Using the flowchart in IMC 0609, Appendix I, this performance deficiency was considered for traditional enforcement because it resulted in the compromise of an examination which affected the equitable and consistent administration of the test or examination against 10 CFR 55.49.

Enforcement: 10 CFR 55.49 states, in part, that “Applicants, licensees, and facility licensees shall not engage in any activity that compromises the integrity of any application, test, or examination required by this part. The integrity of a test or examination is considered compromised if any activity, regardless of intent, affected, or, but for detection, would have affected the equitable and consistent administration of the test or examination. This includes activities related to the preparation and certification of license applications and all activities related to the preparation, administration, and grading of the tests and examinations required by this part.”

Licensee procedure TR-AA-220-1004, Licensed Operator Continuing Training Annual Operating and Biennial Written Exams, section 4.4.3.4 states, in part, “Remedial exams should be developed as required in accordance with TR-AA-230-1004, SAT Implementation. No questions are to be repeated from the original examination without significant modification.”

Contrary to the above, on December 12, 2014, the integrity and compromise of a remedial Licensed Operator Continuing Training Biennial Written Exam, but for detection, affected the equitable and consistent administration of the examination when licensee procedure TR-AA-220-1004 was not adhered to and the examination was administered with one question that was repeated from the initial Licensed Operator Continuing Training Biennial Written Exam without significant modification.

Prior to detection, the operator received the minimum passing score (80%) on the remedial examination and had correctly answered the duplicated question. Removing the repeated question from the remedial Licensed Operator Continuing Training Annual Operating and Biennial Written Exam, as is appropriate, caused the operator to actually have failed the exam. Since, the operator did not pass the required examination, the required licensee training program was not completed, and thus the conditions of the operators' license were not met. Because the error was not detected, the operator was allowed to resume all licensed operator duties and remained on-shift from December 2014 to August 2015.

On August 18, 2015, the licensee identified that the violation had occurred while performing a focused self-assessment in preparation for a NRC biennial licensed operator requalification program inspection. The licensee subsequently removed the individual from licensed operator duties, evaluated his performance on licensed operator continuing training simulator scenarios and program exams, and administered another remedial examination. The individual received a passing grade on the second remedial examination and was returned to licensed operator duties. The licensee informed the NRC staff when the problem was identified.

In accordance with the NRC Enforcement Policy, this performance deficiency was classified as an SLIV violation (Section 6.4.d). Because this violation was not repetitive or willful, and was entered in the licensee's CAP as CR # 02067887, the violation is being treated as an NCV, consistent with section 2.3.2 of the NRC Enforcement Policy. NCV 05000335, 389/2015004-02, Non-willful Compromise of a Remedial Examination Required by 10 CFR 55.59 Affected the Equitable and Consistent Administration of the Exam.

A Green finding was identified for the same performance deficiency which did not involve enforcement action because there was no violation of regulatory requirements relating to exam integrity based solely on the performance deficiency. Because the finding does not involve a violation and is of very low safety significance it is identified as a FIN 05000335, 389/2015004-02, NRC Biennial Remedial Written Examination Contained Exact Duplicate Question.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the performance data and associated ARs for four equipment issues as listed below to verify that the licensee's maintenance efforts met the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" and licensee administrative procedure ADM-17-08, "Implementation of 10 CFR 50.65, The Maintenance Rule (MR)." The inspectors focused on MR scoping, characterization of maintenance problems and failed components, risk significance, determination of MR a(1) and a(2) classification, corrective actions, and the appropriateness of established performance goals and monitoring criteria. The inspectors also interviewed responsible engineers and observed some of the corrective maintenance activities. The inspectors attended applicable expert panel meetings and reviewed associated system health reports. The inspectors verified that equipment problems were being identified and entered into the licensee's CAP. This inspection constitutes four samples. Documents reviewed are listed in the Attachment.

- AR 2053060, 1A EDG abnormal noise after start
- AR 2081028, 2A HPSI pump failed to start during surveillance testing
- AR 2078667, 1-HCV-21-7B, ICW DFS backwash valve will not close
- AR 2027841, 2B CCW HX leaking tubes

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors completed in-office reviews, plant walkdowns, and control room inspections of the licensee's on-line and shutdown risk assessment of the emergent or planned maintenance activities listed below. The inspectors verified the licensee's risk assessment and risk management activities using the requirements of 10 CFR 50.65(a)(4); the recommendations of Nuclear Management and Resource Council 93-01, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants;" and licensee procedure ADM-17.16, "Implementation of the Configuration Risk Management Program." The inspectors also reviewed the effectiveness of the licensee's contingency actions to mitigate increased risk resulting from the degraded equipment. The inspectors interviewed responsible senior reactor operators on-shift, verified actual system configurations, and specifically evaluated results from the online risk monitor (OLRM) for the combinations of OOS risk significant SSCs listed below. This inspection constitutes five samples. Documents reviewed are listed in the Attachment.

- Unit 1 OLRM assessment with the 1A startup transformer (SUT) OOS
- Unit 2 Shutdown safety assessment (SSA) during Mode 6 and in reduced inventory and lowered inventory reactor coolant level
- Unit 2 OLRM during transition to entering Mode 3 greater than 1,750 psia RCS pressure
- Unit 1 OLRM assessment with 1B EDG OOS for planned maintenance
- Unit 2 OLRM while containment cooler HVS-1C, 2B CCW HX, 2B HPSI pump and 2B containment spray pump were OOS

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments

Quarterly Review

a. Inspection Scope

The inspectors reviewed the interim dispositions and operability determinations or functionality assessments of the following ARs to ensure that they were properly supported and the affected SSCs remained available to perform their safety function with no increase in risk. The inspectors verified the operability determinations or functionality assessments were performed in accordance with licensee procedure EN-AA-203-1001, "Operability Determinations and Functionality Assessments." The inspectors reviewed the applicable updated Final Safety Analysis Report (UFSAR) sections, associated supporting documents and procedures, and interviewed plant personnel to assess the adequacy of the interim dispositions. This inspection constitutes five samples.

- AR 01955927, "Channels 7 and 8 Alarming," dated 04/08/2014, and AR 02011678, "Design Basis Review for Steam Generator Tubesheet Design," dated 12/08/14 – Long Term Operability Evaluation for Foreign Material Damage in SG 2B Hot Leg Channel
- AR 2072686, 2B CCW Heat Exchanger Fouling
- AR 2088555, ICW Piping Through-wall Leak 2B CCW Heat Exchanger
- AR 2084573, Unit 2 MV-09-11 Seat Leakage
- AR 2096545, High differential pressure across debris filter system during 1A ICW pump test

b. Findings

No findings were identified.

1R18 Plant Modifications

a. Inspection Scope

The inspectors reviewed the engineering change (EC) documentation for the permanent modifications listed below. The inspectors reviewed the modifications to verify they were implemented as described in procedure EN-AA-205-1100, "Design Change Package." The inspectors reviewed the 10 CFR 50.59 screenings and evaluations, fire protection reviews, and environmental reviews to verify that the modifications had not affected system operability and availability. The inspectors reviewed associated plant drawings and UFSAR documents impacted by these modifications and discussed the changes with licensee personnel to verify the installations were consistent with the modification documents. The inspectors observed portions of each modification installation. Additionally, the inspectors verified that any issues associated with the modifications were identified and entered into the licensee's CAP. This inspection constitutes two samples.

- EC 282327, Fukushima Flex Storage Cabinets for low pressure safety injection (LPSI) at Elevation -0.50'

- EC 279191, PSL Unit 2 Flex Connections – RWT, condensate storage tank (CST), AFW, LPSI, ICW, FS and DOST

b. Findings

No findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

For the maintenance WOs listed below, the inspectors reviewed the test procedures and either witnessed the testing or reviewed test records to determine whether the scope of testing adequately verified that the work performed was correctly completed and demonstrated that the affected equipment was functional and operable. The inspectors verified that the requirements of licensee procedure ADM-78.01, "Post Maintenance Testing," were incorporated into test requirements. This inspection constitutes five samples.

- WO 40283964, 2A EDG excitation system replacement
- WO 38024491, Replace 2A AFW pump motor
- WO 40333085, Unit 2, replace local DC line starter on MV-09-12
- WO 40330824, Replace 1B EDG speed switch
- WO 40224965 and 40224966, ICW isolation Motor Valves MV-21-2 and MV-21-3 static tests after repair

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities

Unit 2 Refueling Outage SL2-22

a. Inspection Scope

Outage Planning, Control and Risk Assessment

The Unit 2 planned RFO started on September 8, 2015. Inspection activities previously completed were documented in NRC Integrated Inspection Report 05000335/2015003, 05000389/2015003 (ML15309A146).

The inspectors reviewed the risk reduction methodology employed by the licensee during various daily RFO SL2-22 meetings, including the outage command center (OCC) morning meetings, operations team meetings, and schedule performance update meetings. The inspectors examined the licensee implementation of SSAs during RFO SL2-22 in accordance with licensee procedure OM-AA-101-1000, "Shutdown Risk Management," to verify whether a defense-in-depth concept was in place to ensure safe operations and avoid unnecessary risk. In addition, the inspectors regularly monitored OCC activities and interviewed responsible OCC management to ensure system, structure, and component configurations and work scope were consistent with TS requirements, site procedures, and outage risk controls. Documents reviewed are listed in the Attachment.

Outage Activities

The inspectors examined outage activities to verify that they were conducted in accordance with TS, licensee procedures, and the licensee's outage risk control plan. Some of the more significant inspection activities accomplished by the inspectors were as follows:

- Walked down selected safety-related equipment clearance orders
- Verified operability of RCS pressure, level, flow, and temperature instruments during various modes of operation
- Verified electrical systems availability and alignment
- Verified shutdown cooling system and spent fuel pool (SFP) cooling system operation
- Evaluated implementation of reactivity controls
- Reviewed control of containment penetrations
- Examined foreign material exclusion controls put in place inside containment (e.g., around the refueling cavity, near sensitive equipment and RCS breaches)

Fatigue Management Activities

The inspectors verified the licensee had scheduled covered personnel such that the minimum days off for individuals working on outage activities were in compliance with 10 CFR 26.205(d)(4) and (5). In addition, the inspectors reviewed the two waiver requests generated during the outage to verify the licensee met the CFR requirements. There were no self-declarations or fatigue assessments completed during the outage.

Refueling Activities and Containment Closure

The inspectors witnessed selected fuel handling operations being performed according to TS and applicable operating procedures from the main control room, the refueling cavity inside containment, and the SFP. The inspectors also examined licensee activities to control and track the position of each fuel assembly. The inspectors evaluated the licensee's ability to close the containment equipment, personnel, and emergency hatches in a timely manner per procedure 2-GMM-68.02, "Emergency Closure of Containment Penetrations, Personnel Hatch, and Equipment Hatches."

RCS Mid-Loop Inventory Condition

The inspectors reviewed the planned activities associated with a period of reduced RCS inventory established in order to remove the 2B SG nozzle dams and to restore the 2B SG primary side manways. The inspectors verified the licensee had controls in place to govern the reduced inventory conditions. The inspectors verified that the necessary instrumentation and means of adding inventory to the RCS were available.

Heat-up, Mode Transition, and Reactor Startup Activities

The inspectors examined selected TS, license conditions, and license commitments, and verified administrative prerequisites were being met prior to Mode changes. The inspectors also reviewed measured RCS leakage rates, and verified containment integrity was properly established. The inspectors performed a containment sump closeout inspection prior to reactor plant startup and conducted a containment walkdown prior to restarting the unit. The results of low power physics testing were discussed with Reactor Engineering and Operations personnel to ensure that the core operating limit parameters were consistent with the design. The inspectors witnessed portions of the RCS heat up, reactor startup, and power ascension in accordance with the following plant procedures:

- 2-PTP-81, "Reload Startup Physics Testing"
- 2-PTP-91, "Unit 1 Initial Criticality Following Refueling"
- 2-GOP-302, "Reactor Startup Mode 3 to Mode 2"
- 2-GOP-201, "Reactor Plant Startup Mode 2 to Mode 1"

Corrective Action Program

The inspectors reviewed ARs generated during SL2-22 to evaluate the licensee's threshold for initiating ARs. The inspectors routinely reviewed the results of Quality Assurance (QA) daily surveillances of outage activities.

Inspections completed during this inspection period along with the inspections completed as documented in NRC Integrated Inspection Report 05000335/2015003, 05000389/2015003 (ML15309A146) constitutes one inspection sample.

b. Findings

No findings were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors either reviewed or witnessed the following surveillance tests to verify that the tests met TS, UFSAR, and licensee procedural requirements. The inspectors verified the tests demonstrated operational readiness, and that systems were capable of performing their intended safety functions. In addition, the inspectors evaluated the effect of the testing activities on the plant to ensure conditions were adequately addressed by the licensee staff, and after completion of the testing activities, equipment was returned to standby alignment required for the system to perform its safety function. The inspectors verified that surveillance issues were documented in the CAP. The inspectors verified the licensee properly changed the surveillance test interval from 18-months to 36-months for operations surveillance procedure (OSP) 2-OSP-13A in accordance with NEI 01-10, "Risk-Informed Method for Control of Surveillance Frequencies," as allowed by TS surveillance requirement (SR) 4.5.2. This inspection constitutes seven samples. Documents reviewed are listed in the Attachment.

In-Service Tests:

- 2-OSP-03.01A, 2A HPSI Pump Safeguards Full Flow Test
- 2-OSP-21.01A, 2A ICW Pump Code Run; and 2-OSP-21.01C, 2C ICW Pump Code Run (total of one sample)

Surveillance Tests:

- 2-PTP-81, Reload Startup Physics Testing
- 2-OSP-09.02C, 2C AFW Refueling Shutdown Pump and Valve Test
- 2-OSP-36.13A, ESF – Staggered 36 Month Surveillance For SIAS/CIS/CSAS – Train A
- CY-SL-102-0008, Determination Of Chlorine Using Hach Pocket Colorimeter
- 1-OSP-21.01B and 1-OSP-21.01C, 1B and 1C ICW Pump Code Run

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness (EP)

1EP6 Drill Evaluation

Emergency Preparedness Drills

a. Inspection Scope

On December 9, 2015, the inspectors observed the simulator control room, technical support center, and emergency operations facility staff during a drill of the site emergency response organization to verify the licensee was properly classifying emergency events, making the required notifications, and making appropriate protective action recommendations. The scenario included a progressively worsening reactor coolant leak that developed into a LOCA, a reactor trip, a safety injection actuation, and a temporary loss of all safety injection flow after an EDG failed to start. A Notice of Unusual Event, an Alert, a Site Area Emergency, and later, a General Emergency were declared due to degrading plant conditions. During the drill, the inspectors assessed the licensee's actions to verify that emergency classifications and notifications were made in accordance with licensee emergency plan implementing procedures (EPIPs) and 10 CFR 50.72 requirements. The inspectors specifically verified the Alert, Site Area Emergency, and General Emergency classifications and notifications were made in accordance with licensee procedures EPIP-01, "Classification of Emergencies" and EPIP-02, "Duties and Responsibilities of the Emergency Coordinator." The inspectors also observed whether the initial activation of the emergency response centers was timely and as specified in the licensee's emergency plan. The inspectors also verified that the licensee identified critique items and drill weaknesses were captured in their CAP. This inspection constitutes one sample.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

.1 Mitigating Systems Cornerstone

a. Inspection Scope

The inspectors checked licensee submittals for the Unit 1 and Unit 2 mitigating system performance indicators (PIs) listed below to verify the accuracy of PI data reported during the period of October 1, 2014 through September 30, 2015. Performance Indicator definitions and guidance contained in NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” and licensee procedure ADM-25.02, “NRC Performance Indicators,” were used to check the reporting for each data element. The inspectors checked operator logs, plant status reports, CRs, system health reports, and PI data sheets to verify that the licensee had identified the required data, as applicable. The inspectors interviewed licensee personnel associated with PI data collection, evaluation, and distribution. This inspection constitutes five samples for each unit.

- Emergency AC power
- Residual heat removal system
- Heat removal system
- HPSI
- Cooling water system

a. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems

.1 Daily Review

a. Inspection Scope

As required by IP 71152, “Identification and Resolution of Problems,” and to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a screening of items entered daily into the licensee’s CAP. This review was accomplished by reviewing daily printed summaries of ARs, and by reviewing the licensee’s electronic AR database. Additionally, RCS unidentified leakage was checked on a daily basis to verify no substantive or unexplained changes existed.

b. Findings

No findings were identified.

.2 Annual Sample: 1A Emergency Diesel Generator Abnormal Sounds and Indication After Starting

a. Inspection Scope

The inspectors selected AR 2053060, "1A Emergency Diesel Generator Abnormal Sounds and Indication After Starting," for a more in-depth review of the circumstances and the corrective actions that followed. The inspectors reviewed the AR report to ensure that the licensee performed an appropriate evaluation, and specified and prioritized corrective actions in accordance with its program. Other attributes checked included disposition of operability and resolution of the problem, including cause determination, past operability determination, and corrective actions. The inspectors interviewed plant personnel and evaluated the CR in accordance with the requirements of the licensee's corrective actions process as specified in licensee's procedure PI-AA-104-1000, "Corrective Action." This inspection constitutes one sample.

b. Observations

The licensee's ACE determined that the failure of the 1A EDG to properly start was due to the failure of its speed switch in the control circuitry. The licensee determined that although it was known that the speed switches for the EDGs were obsolete, it was not recognized that the speed switch was at its end-of-life, as recommended by the manufacturer. Due to obsolescence, the EDG system engineer implemented plans to replace the switches. The 2B EDG speed switch was replaced in 2014. The EDG speed switches for 1A EDG, 2A EDG, and 1B EDG were scheduled to be replaced in 2016, fall 2015, and 2017, respectively. Immediate corrective actions included replacing the 1A EDG speed switch with a new style speed switch. Additional corrective actions completed include replacement of the 2A EDG and the 1B EDG speed switches.

The licensee concluded that the failure of the 1A EDG to properly start was a maintenance preventable functional failure since timely replacement of the speed switches could have prevented the failure. The EDG ESI-EMD Owners group maintenance program recommends speed switch replacement every 10 years, based on aluminum electrolytic capacitor life expectancy. The inspectors' review of this event found no evidence that the licensee considered this vendor recommendation. In addition, it is a well-known industry issue that electrolytic capacitors have a finite life expectancy. The licensee was unable to find a record of when the failed 1A EDG speed switch was installed.

c. Findings

No findings were identified. A licensee identified violation is documented in Section 4OA7 of this report.

.3 Annual Sample: Biological Fouling of the 2B CCW Heat Exchanger

a. Inspection Scope

The inspectors performed an in-depth review of ACE ARs 02027841 and 02072686 relating to fouling of the 2B CCW HX. The inspectors reviewed the circumstances and corrective actions related to the determination of both ACEs that inadequate SH injection to the HX resulted in one instance of biological fouling and tube leakage and one instance of extensive fouling. The inspectors reviewed the Westinghouse evaluation of the 2B CCW HX, which determined that the HX had remained operable even with the extensive fouling that caused tube blockage in excess of the analyzed limit for blocked tubes. The inspectors observed a Unit 2 chemistry surveillance that tested for SH at the outlet of the CCW HXs and reviewed two years of chemistry surveillance data to determine if the surveillances were being performed as scheduled. The inspectors interviewed chemistry technicians, licensed operators, and the responsible system engineer for the ICW and CCW systems to assess the current status of the SH system. The inspectors evaluated the licensee's disposition of the selected ARs to verify whether the licensee's actions were in accordance with licensee procedure, PI-AA-104-1000, "Corrective Action." Documents reviewed are listed in the Attachment. This inspection constitutes one sample.

b. Observations

The licensee's HX program does not include routine thermal performance testing of the CCW HXs for verifying continued operability. In place of testing, periodic inspections and preventive maintenance are completed during the operating cycle and outages. Specifically, by Florida Power and Light (FPL) letter L-90-28, dated 01-25-90, the licensee provided a response to the Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." Under Action I of the Generic Letter, the licensee committed to "inspecting the intake structure and piping for macroscopic biological fouling every refueling outage, cleaning, if necessary, and chlorinating the system up to the limits allowed by environmental laws." These generic letter actions are also documented in both Units' UFSAR. Chlorination is implemented via continuous injection of SH to the ICW system in order to control biological fouling and prevent erosion/corrosion of the tube walls. This is a key element used to ensure continued operability of the HXs.

Review of three years of the CAP database shows that continuous injection of SH has not been consistently accomplished, and at times there was little to no injection due to low system reliability. In 2013, the licensee identified a degrading trend associated with the health of the common SH system that provides SH injection to both units, and this issue was documented in AR 0188329. This AR described a degrading trend in health and timeliness of maintenance and recommended that the health and monitoring of the system be evaluated and a recovery plan be developed. The inspectors determined that no evaluation or plan was developed. In 2014, issues with SH injection to the ICW system remained unresolved, and repeated repairs caused the system to remain OOS for extended periods of time. Issues included clogging of SH piping to the ICW pump suction, corrosion of supports, a non-functional pump, and leaks in injection lines and in the auxiliary tank which holds the SH. In 2014, AR 02002575 documented continued system degradation and unavailability and initiated an action to replace the SH system with a more reliable system. Long term asset management plan LTAM-PSL-14-0042 was developed to implement a modification to replace the SH system with a more reliable system, but no implementation date was specified. In 2015, AR 02076834 documented that for six months, from January to June of 2015, the SH chemistry surveillance data was missing; however the AR evaluation was inconclusive as to whether the surveillances had in fact been completed. The inspectors reviewed the details of this issue and concluded that the six months of surveillances were not completed.

In reviewing the corrective actions associated with the 2B CCW HX tube leaks identified in February of 2015, the inspectors found there were no interim corrective actions for the apparent cause to address the immediate issue of inadequate SH injection and the continued fouling. Instead, only a long term corrective action to implement LTAM-PSL-14-0042 to replace the SH system by July of 2015 was specified. In September of 2015 the same HX was found to be fouled to the point of exceeding the analyzed maximum number of plugged tubes. The apparent cause was again inadequate SH injection to the ICW system. The inspectors determined that the corrective action for the February 2015 tube leakage issue that specified replacing the SH system by July 2015 was not completed. The inspectors questioned the licensee on the current health of the SH system. The inspectors were initially told that utilizing a temporary tank on the degraded SH system was adequate to ensure proper injection to the ICW system until the new SH system could be installed. Through discussions with chemistry and operations personnel, the inspectors determined that temporary tank was a small capacity tank that did not provide for continuous injection to the ICW system. SH was only injected into the ICW system three times a week for about 14 hours each time. The inspectors reviewed this issue with plant management, and an operations representative was assigned to address all immediate issues associated with the SH system to ensure continuous injection. On December 7, 2015, three additional temporary SH tanks were installed, allowing continuous daily injection to the ICW system.

The inspectors completed a past operability review sample of the 2B CCW HX, which is documented in section 1R15 of this report. The inspectors identified a violation of NRC requirements as described below.

c. Findings

Introduction: An NRC identified Green NCV of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” was identified for the licensee’s failure to implement corrective actions to prevent fouling of the 2B CCW HX that resulted in the number of blocked tubes exceeding the maximum analyzed limit for plugged tubes.

Description: On February 24, 2015, the 2B CCW HX was removed from service to repair three leaking tubes. Apparent cause evaluation AR 02027841 concluded that the marine fouling and debris in the tube side of the HX and erosion/corrosion of the internal tube walls were the causes of the tube leaks. Inadequate SH injection was attributed as the cause of shell growth and marine fouling in the HX. The licensee identified that implementation of LTAM-PSL-14-0042 was not timely enough to prevent the failure of the 2B CCW HX tubes. The HX was returned to service on March 14, 2015. Corrective actions for the apparent cause was to implement LTAM-PSL-14-0042 by July 15, 2015.

On September 9, 2015, during the end-of-cycle inspection of the 2B CCW HX, the licensee found extensive marine fouling obstructing the tubes. Approximately two gallons of marine shells were collected from the bottom surface of the inlet channel head. In total, 580 tubes were identified that were either fully or partially blocked due to fouling. An additional 103 tubes had previously been mechanically plugged. The total blocked tube count exceeded the analyzed limit of 200 plugged tubes for the HX. Apparent cause evaluation AR 2072686 identified the cause of the extensive marine fouling was attributed to unreliable SH chemical injection to the 2B CCW HX, and to flushing of the ICW DFS just prior to entering the RFO. Corrective actions included completing the SH system replacement, LTAM-PSL-14-0042, by March 1, 2016. Interim corrective actions included implementing mid-cycle cleaning of CCW HXs. A past operability review of the HX performance was performed with a period of concern from March 14 to September 9, 2015. Heat loads from two main analyses were used: 1) St. Lucie Unit 2 Containment LOCA Pressure and Temperature Analysis; and 2) St. Lucie Unit 2 extended power uprate (EPU) CCW/ICW Temperature Response Analysis. In lieu of the design input temperature of 95°F, the actual maximum ICW inlet temperature used was 87.5°F over this period of concern. The results showed that HX performance did not meet the requirement of either of the analyses. Westinghouse was contracted to complete an analysis and identify areas of margin within the analyses that could be altered to demonstrate operability using actual values for the period of concern. The licensee concluded that the 2B CCW HX had remained operable but degraded and was capable of performing its specified safety functions for the period of concern.

The inspectors were initially told that utilizing a temporary tank on the degraded SH system was adequate to ensure proper injection to the ICW system until the new SH system could be installed. Through discussions with chemistry and operations personnel, the inspectors determined that temporary tank was a small capacity tank that did not provide for continuous injection to the ICW system. SH was only injected into the ICW system three times a week for about 14 hours each time. The inspectors reviewed this issue with plant management, and an operations representative was assigned to address all immediate issues associated with the SH system to ensure continuous injection. On December 7, 2015, three additional temporary SH tanks were installed, allowing continuous daily injection to the ICW system.

Analysis: The licensee's failure to implement adequate corrective actions to prevent the Unit 2B CCW HX from becoming fouled due to a lack of SH, to the point of exceeding the analyzed limit for blocked tubes, was a performance deficiency and was within the licensee's ability to prevent. The performance deficiency was more-than-minor because if left uncorrected, the performance deficiency had the potential to lead to a more significant safety concern. Specifically, inadequate SH injection may cause extensive fouling and can lead to a common mode failure of the CCW HXs, preventing the required cooling of safety-related SSC's analyzed heat loads during a DBA. Using Manual Chapter 0609.04, "Significance Determination Process Initial Characterization of Findings," Table 2, dated June 19, 2012, the finding was determined to affect the Mitigating Systems Cornerstone. Manual Chapter 0609 Appendix A, "The Significance Determination (SDP) Process for Findings At-Power," Exhibit 2 "Mitigating Systems Screening Questions." dated June 19, 2012, was used to further evaluate this finding. The finding screened as Green because the finding represented neither an actual loss of function of at least a single train for greater than its TS Allowed Outage Time, nor two separate safety systems OOS for greater than its TS Allowed Outage Time. The finding involved the cross-cutting area of the resolution component in PI&R because the organization did not take effective corrective actions to address issues in a timely manner commensurate with the safety significance of the CCW HX. Specifically, even after the repeat fouling issue had been identified on 2B CCW HX, there was no immediate resolution of inadequate SH injection until the inspectors addressed this issue with plant management [P.3].

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions,” requires, in part, that conditions adverse to quality, such as deficiencies and non-conformances, are promptly identified and corrected. Contrary to the above, between March 14 and December 7, 2015, the licensee failed to correct a condition adverse to quality. Specifically, on March 14, 2015, after the licensee identified there was inadequate SH injection to the ICW system that resulted in extensive fouling of the 2B CCW HX which caused tube leaks, the licensee did not implement adequate corrective actions to prevent the same HX from being fouled to the point of exceeding its maximum analyzed number of plugged tubes, a condition that was identified on September 9, 2015. Corrective actions to inject adequate SH to the ICW system were not implemented until December 7, 2015. Because this violation was of very low safety significance (Green), and it was entered into the licensee’s CAP as AR 02097971, it is being treated as a NCV consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000335,389/2015004-03, Inadequate Corrective Actions to Prevent Fouling of The CCW HX).

.4 Semi-Annual Trend Review:

a. Inspection Scope

The inspectors performed a review of the licensee’s CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors’ review was focused on repetitive equipment issues, and also considered the results of daily inspector CAP items screening discussed in section 4OA2.1, plant status reviews, plant tours, and licensee trending efforts. The inspectors’ review nominally considered the six-month period of June 2015 through December 2015, although some examples extended beyond those dates when the scope of the issue warranted. The inspectors evaluated the licensee’s administration of the ARs in accordance with the CAP, as specified in licensee procedure PI-AA-104-1000, “Corrective Action.” Documents reviewed are listed in the Attachment. This inspection constitutes one sample.

b. Observations

The inspectors identified a negative trend associated with installed scaffolds not meeting licensee procedure requirements. Procedure MA-AA-100-1002 allows scaffolds to be installed within two inches of safety-related SSCs, as long as an engineering evaluation shows that this is acceptable. The inspectors noted nine examples of scaffolds located within two inches of safety-related SSCs which lacked an engineering evaluation. The regulatory significance of this issue is documented below.

c. Findings

Introduction: The NRC identified a Green NCV of TS 6.8.1, “Procedures and Programs,” for the licensee’s failure to properly implement written procedures covering activities referenced in NRC Regulatory Guide 1.33, Revision 2, dated February 1978. Specifically, the licensee routinely failed to complete engineering evaluations to determine the acceptability of scaffolds that did not meet the 2-inch clearance requirement of NextEra Nuclear Fleet Administrative Procedure MA-AA-100-1002, “Scaffold Installation, Modification, and Removal Requests.”

Description: Between June 9, 2015 and October 23, 2015, the NRC inspectors identified six scaffolds located within two inches of safety-related SSCs that did not have an engineering evaluation approving the installation, as required by MA-AA-100-1002. Placing scaffolds within close proximity to safety-related SSCs poses a risk of rendering the equipment inoperable under normal and adverse conditions such as a seismic event. Placement of scaffold within two inches of safety-related SSCs is permitted by MA-A100-1002, as long as an engineering evaluation determines that this is acceptable. The licensee documented the six as-listed scaffold non-compliances in the CAP.

- AR 02052985, scaffold within 2 inches of the Unit 2 centrifugal fan for control room return systems, 2-HVE-13A
- AR 02071846, scaffold within 2 inches of the Unit 1 CCW surge tank overflow pipe
- AR 02077507, scaffold within 2 inches of the Unit 1 “C” charging system piping, which made direct contact with insulation on the piping
- AR 02083464, scaffold within 2 inches of the Unit 2 main feed isolation valve, HCV-08-2A
- AR 02083435, the licensee erected a scaffold within 2 inches of the Unit 2 CCW DFS
- AR 02084290, the licensee erected a scaffold within 2 inches of the Unit 2 main feed isolation valve, HCV-09-1A

The licensee’s extent-of-condition review identified three additional scaffolds located within two inches of safety-related SSCs that did not have an engineering evaluation as noted below.

- AR 02077581, the licensee erected a scaffold within 2 inches of the Unit 1 “C” charging pump discharge line
- AR 02085015, the licensee erected a scaffold within 2 inches of the Unit 2 “B” ICW pump motor base and lower motor site glass
- AR 02084999, the licensee erected a scaffold within 2 inches of Unit 2 containment electrical penetrations

Following the identification of the scaffold non-compliances, the licensee implemented prompt corrective action to restore compliance with MA-AA-100-1002 by repositioning/reworking or removing the scaffolds. The licensee initiated a severity level-2 ACE in response to one of the NRC identified scaffold installation non-compliances (AR 02077507). The ACE addressed the programmatic nature of the issue and concluded a lack of attention to detail existed during the installation and post installation inspections of erected scaffolds. The contributing causes included ineffective change management to scaffold procedure changes and ineffective corrective actions. Corrective actions included implementing a post installation inspection by FPL supervision and contractor senior leadership for future scaffolds.

Analysis: The licensee’s repeated failure to erect scaffolds in compliance with the NextEra Nuclear Fleet Administrative Procedure, MA-AA-100-1002, was a performance deficiency. The performance deficiency was more-than-minor because it was associated with the Mitigating Systems Cornerstone attribute of protection against external factors, seismic, and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, routinely failing to complete engineering evaluations of scaffold-clearance issues could lead to the continued use of inadequately installed scaffolds, which could ultimately pose a risk of rendering safety-related equipment inoperable during normal and adverse conditions such as a design basis seismic event. Using Inspection Manual Chapter 0609, Attachment 4, "Initial Characterization of Findings," Table 2, "Cornerstones Affected by Degraded Condition or Programmatic Weakness," dated June 19, 2012, the inspectors determined the finding affected the Mitigating Systems Cornerstone. Inspection Manual Chapter 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," dated June 19, 2012, was used to further evaluate this finding. The finding screened as Green because "no" was answered to all four screening questions, i.e. the finding did not represent an actual loss of function of any piece of plant equipment for any amount of time. The finding involved the cross-cutting area of PI&R in the aspect of resolution, in that the organization did not take effective corrective actions to address the scaffolding issues in a timely manner, as evidenced by a period of five months in which the inspectors continued to identify non-conformances with erected scaffold [P.3].

Enforcement: Technical Specification 6.8.1, "Procedures and Programs," requires, in part, that written procedures be implemented covering activities referenced in Regulatory Guide 1.33, Revision 2, dated February 1978, including safety-related activities carried out during operation of the plant. Section 9.a, "Procedures for Performing Maintenance," states, in part, that maintenance which can affect the performance of safety-related equipment should be properly pre-planned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances.

NextEra Nuclear Fleet Administrative Procedure MA-AA-100-1002, Revision 2, "Scaffold Installation, Modification, and Removal Requests," Section 4.1.3, "Inspections and Tagging," requires that if scaffold cannot meet a 2-inch clearance to plant equipment requirement, engineering approval must be documented.

Contrary to the above, between June 9, 2015 and October 23, 2015, nine erected scaffolds were found to be located within two inches of safety-related plant equipment, and engineering evaluations were not completed approving the installation and use of the scaffolds. Corrective actions included repositioning/reworking or removing scaffolds that were not in compliance with the clearance requirement of MA-AA-100-1002. Because the licensee has restored compliance and entered this issue into its CAP as AR 02077507, and because the finding is of very low safety significance (Green), this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC's Enforcement Policy (NCV 05000335,389/2015004-04, Procedural Non-compliances Relating to Installed Scaffold Located Near Safety-related SSCs).

.5 <u>(Closed) Unresolved Item 05000335,-389/2014005-02, Design Basis Review for Unit 1 and Unit 2 Steam Generator Tube-to-Tubesheet Joint</u>

a. <u>Inspection Scope</u>

The NRC Inspection Report 2014005, dated January 30, 2015 (ADAMS Accession Number ML15030A323), included an unresolved item (URI) associated with the design basis of the Unit 2 replacement steam generator (RSG) tube-to-tubesheet welds. On May 6, 2015, the NRC revised the URI to include Unit 1 within the scope of the issue of concern (ADAMS Accession Number ML15126A323). The NRC identified the URI during the review of licensee's corrective actions to address foreign material damage in the hot leg channel of Unit 2 steam generator (SG) 'B'. The URI was related to the design approach of the tube-to-tubesheet weld for the Unit 1 and Unit 2 RSGs.
From October 1, 2015, to December 31, 2015, the inspectors conducted interviews with licensee staff, and reviewed design basis information for the Unit 1 and Unit 2 RSGs, to verify that the design and fabrication of the tube-to-tubesheet welds met the applicable codes and regulatory requirements. The inspectors' review focused on vendor calculations that were developed to address the URI. The inspectors also reviewed the impact of the issue of concern on the conclusions of the original 10 CFR 50.59 evaluations for the RSGs of both units. All documents reviewed for the resolution of this issue are listed in the report Attachment.

b. <u>Findings and Observations</u>

1. <u>Failure to Verify the Adequacy of the Unit 1 and Unit 2 Replacement Steam Generators Tube-to-Tubesheet Weld Design</u>

<u>Introduction:</u> A Green, NRC-identified, Non-cited Violation (NCV) of 10 CFR Appendix B, Criterion III, "Design Control," was identified for the failure to verify the adequacy of the Unit 1 and Unit 2 RSGs design with respect to the requirements in the American Society of Mechanical Engineers (ASME) Code, Section III, Article NB-3000, for the primary stress and fatigue analyses of the tube-to-tubesheet welds.

<u>Description:</u> Certified Design Specification document F-MECH-SP-002, "Engineering Specification for Replacement Steam Generator Assemblies for Florida Power and Light Co. – St. Lucie Unit 1," Revision 3, stated that the design and fabrication of the Unit 1 RSGs conforms with the requirements of the ASME Code, Section III, "Rules for Construction of Nuclear Power Plant Components," 1986 Edition with no Addenda. Similarly, Certified Design Specification document SGRP-SPEC-M-009, "Certified Design Specification for Replacement Steam Generators St. Lucie Unit No. 2," Revision 2, stated that the design and fabrication of the Unit 2 RSGs conforms with the requirements of the ASME Code, Section III, 1998 Edition through 2000 Addenda. The Unit 1 and Unit 2 RSGs were installed in 1997 and 2007, respectively, and are categorized as safety-related components. Therefore, the design and fabrication of these components are subject to the requirements in 10 CFR Part 50, Appendix B, "Quality Assurance."

The fabrication of the tube-to-tubesheet joints in the Unit 1 and Unit 2 RSGs generally consisted of inserting the U-bend tubes into dedicated tubesheet drilled holes, welding the two ends of each tube to the bottom surface of the tubesheet, and then radially expanding the portion of the tubes inserted in the tubesheet drilled holes. In the original

SGs, the tube-to-tubesheet welds were designed as part of the pressure-retaining boundary in accordance with the ASME Code, Section III, Article NB-3000. Article NB-3000 establishes limits for primary stresses and fatigue in Class 1 materials that form the pressure-retaining boundary, including welds. The ASME Code, Section III, also specifies fabrication and examination requirements for tube-to-tubesheet welds. Paragraph NB-4350 describes special qualification requirements for tube-to-tubesheet welds; and paragraph NB-5274 requires liquid penetrant examination of the completed welds.

In 2014, during the review of licensee evaluations and corrective actions for foreign material damage in the Unit 2 SG ‘B’, the NRC identified that engineering calculations for the tube-to-tubesheet joint described the tube-to-tubesheet weld as a “seal weld” (See NRC Inspection Report 2014005 mentioned in the inspection scope above). Further review of design information for the RSGs revealed that the vendors did not perform the necessary ASME Code analyses to support the pressure-retaining (or structural) function of the welds, as in the design basis of the original SGs. Specifically, the vendors did not perform the primary stress analyses of the tube-to-tubesheet welds in the Unit 1 and Unit 2 RSGs, to verify that the design basis loads would not result in stresses beyond the limits established in the ASME Code, Section III, Article NB-3000. The NRC also identified that the vendor of the Unit 1 RSGs did not perform a fatigue analysis of the tube-to-tubesheet welds, as required by Article NB-3000.

The inspectors noted that the vendors for the Unit 1 and Unit 2 RSGs implemented different approaches to meet the ASME Code, Section III requirements applicable to pressure-retaining tube-to-tubesheet welds. For Unit 1, the vendor understood that fabricating the tube-to-tubesheet welds per the provisions of NB-4350 and NB-5274 would satisfy all the applicable ASME Code requirements for a pressure-retaining weld. Consequently, no primary stress or fatigue analyses were performed. For Unit 2, the vendor also followed the requirements of NB-4350 and NB-5274 to fabricate the tube-to-tubesheet weld; however, it qualified the entire tube-to-tubesheet joint (tube expansion and welding) for the design basis loads without a specific primary stress analysis of the welds, other than the fatigue analysis. The failure to perform the stress analyses for both Unit 1 and Unit 2 RSGs, in accordance with Article NB-3000, was attributed to the failure of the licensee’s design review process to verify that the RSGs tube-to-tubesheet welds were designed as pressure-retaining welds with the corresponding analyses, and consistent with design basis of the original SGs.

The licensee entered this issue into the corrective action program (CAP) as AR 02035185 (Unit 1), and AR 02011678 (Unit 2). In response to this issue, the licensee performed primary stress analyses for the Unit 1 and Unit 2 RSGs tube-to-tubesheet welds, as well as the fatigue analysis for Unit 1. The analyses demonstrated that the stress limits and fatigue usage factors established in ASME Code, Section III, Article NB-3000 were satisfied under design basis conditions. Therefore, structural integrity of the welds was demonstrated consistent with the design basis. Additionally, the conclusions of the original 10 CFR 50.59 evaluations for the RSGs were not affected, because the tube-to-tubesheet welds were demonstrated to meet the applicable ASME Code requirements.

Analysis: The inspectors determined that the failure to verify the adequacy of the Unit 1 and Unit 2 RSGs design with respect to the requirements in the ASME Code, Section III, Article NB-3000, for the primary stress and fatigue analyses of the pressure-retaining tube-to-tubesheet welds, was a performance deficiency (PD). The inspectors used the guidance in NRC Inspector Manual Chapter (IMC) 0612, Appendix B, "Issue Screening," dated September 7, 2012, and determined that the PD was more-than-minor because it was associated with the design control attribute of the Initiating Events Cornerstone, and adversely affected the cornerstone objective. Specifically, the failure to verify that the required stress and fatigue analyses were performed in accordance with the ASME Code did not support the objective of limiting the likelihood of primary-to-secondary leakage events that could upset plant stability, and challenge critical safety functions during shutdown, as well as power operations.

The inspectors determined that the finding affected the Initiating Events Cornerstone based on the attributes described in NRC IMC 0609, Attachment 4, Initial Characterization of Findings, Table 2, dated June 19, 2012. The inspectors further evaluated this finding using NRC IMC 0609, Appendix A, Significance Determination Process for Findings At-Power, Exhibit 1 – Initiating Events Screening Questions, dated June 19, 2012. The finding screened as Green because the final stress and fatigue calculations demonstrated that there was no degraded SG tube condition where one tube could not sustain three times the differential pressure across a tube during normal full power, and none of the SGs violated the "accident leakage" performance criterion. Additionally, the calculations demonstrated that the finding did not result in a condition that exceeded the reactor coolant system leak rate for a small loss of coolant accident (LOCA), or affected other systems used to mitigate a LOCA resulting in a total loss of their function (e.g., Interfacing System LOCA). The inspectors determined that no cross-cutting aspect was associated with this finding because the PD occurred more than 3 years ago, and it was not reflective of present performance.

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, "Design Control," states, in part, that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Contrary to the above, in 1997 and 2007, the licensee failed to establish design control measures, such as performing a design review, to verify the adequacy of the RSGs design with respect to the ASME Code requirements that were translated into the Certified Design Specifications. Specifically, the licensee failed to verify that the vendors performed the required primary stress and fatigue analyses of the Unit 1 RSGs pressure-retaining tube-to-tubesheet welds, and the required primary stress analysis of the Unit 2 RSGs pressure-retaining tube-to-tubesheet welds, in accordance with the ASME Code, Section III, Article NB-3000. The licensee implemented corrective actions to perform the required analyses to demonstrate compliance with the applicable ASME Code, Section III requirements.

Because this violation was determined to be of very low safety significance (i.e., Green), and the licensee entered the issue in the CAP as AR 02035185 and AR 02011678, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy, dated February 4, 2015. This finding will be tracked as NCV 05000335, -389/2015004-05, "Failure to Verify the Adequacy of the Unit 1 and Unit 2 Replacement Steam Generators Tube-to-Tubesheet Weld Design."

2. <u>10 CFR 50.59 Evaluation for the Unit 2 Steam Generator Tube-to-Tubesheet Welds</u>

The guidance used by the licensee for the implementation of 10 CFR 50.59 for the Unit 2 SG replacement project, Nuclear Energy Institute (NEI) document NEI 96-07, "Guidelines for 10 CFR 50.59 Implementation," Revision 1, stated, in part, that methods of evaluation (defined as the calculational framework) described in the UFSAR subject to criterion 10 CFR 50.59(c)(2)(viii) are those used in supporting UFSAR analyses that demonstrate intended design functions will be accomplished under design basis conditions. Title 10 CFR 50.59(d)(1) requires the licensee to maintain records that include a written evaluation which provides the bases for the determination that a change to a method of evaluation described in the UFSAR does not require a license amendment pursuant to paragraph 10 CFR 50.59(c)(2).

The UFSAR in effect just prior to the replacement of the Unit 2 original SGs, Amendment 17, Chapter 3, "Design of Structures, Components Equipment, And Systems," described several computer programs used for the structural design of the original SGs to demonstrate that the pressure-retaining function, as described in Chapter 5, Section 5.4.2.1, "Design Bases," would be accomplished. The vendor of the Unit 2 RSGs (Areva) used computer programs for the structural design of the tube-to-tubesheet joint, and other pressure-retaining components, that were different from the programs described in Chapter 3 of the UFSAR for the design of the original SGs. Areva performed the structural analysis of the RSGs with its own computer programs, BWSPAN and SYSNUKE. The inspectors noted that such change in methods of evaluation was not specifically addressed in the original 10 CFR 50.59 evaluation for the RSGs documented in Areva Report 77-5069878-02, "Replacement Steam Generator Report for Florida Power and Light, St. Lucie Unit 2," dated August 2007.

The inspectors determined that the computer programs described in the UFSAR were methods of evaluation subject to the provisions of 10 CFR 50.59; and thus any changes to these methods required a written evaluation per 10 CFR 50.59(d)(1). The licensee entered this issue in the CAP as AR 02079732, "PSL2 UFSAR Update Needed." The licensee's corrective actions included a revision to the original 10 CFR 50.59 evaluation (Areva Report 77-5069878-02) to include the evaluation of changes in computer programs used for the structural design of the RSGs. The licensee concluded that no departure from a method of evaluation occurred, and therefore no license amendment was required per 10 CFR 50.59, because the original FSAR only provided a general functional description of the computer programs and did not explicitly define the calculational framework behind the structural analysis performed by the computer programs. Additionally, Areva stated that their computer programs met the applicable quality assurance program requirements and were benchmarked against classical solutions and/or other industry acceptable codes. The licensee also provided documentation preceding the installation of the Unit 2 RSGs where the NRC approved the use of BWSPAN for the structural analysis of the reactor coolant system, in support of the SGs replacement at other facility (ADAMS Accession Number ML012490111). Furthermore, in 2011, the licensee informed the NRC about the use of computer programs different from the ones originally described in the UFSAR (including BWSPAN and SYSNUKE) for the structural reevaluation of pressure-retaining components and supports, as part of the license amendment request submitted for the Unit 2 Extended Power Uprate (EPU) (ADAMS Accession Numbers ML110730299 and ML110730301). On September 14, 2012, the NRC issued a safety evaluation report for the EPU license amendment request, and found that the licensee's request was acceptable (ADAMS Accession Number ML12235A46).

The inspectors determined that the failure to maintain a written evaluation, providing the basis for the determination that a license amendment was not required for changes in computer programs described in the UFSAR, was a minor violation of 10 CFR 50.59(d)(1). The violation was determined to be minor in accordance with the guidance in NRC Enforcement Manual, Part III, Appendix E, "Examples of Minor Violations," dated September 9, 2013, since it involved a change to the UFSAR where there was no reasonable likelihood that the change would ever require NRC approval per 10 CFR 50.59. The determination that NRC approval would not be required per 10 CFR 50.59 was based on the fact that: (a) the UFSAR did not provide specific description of the calculational framework behind the computer programs, (b) Areva's BWSPAN and SYSNUKE were qualified under the applicable quality assurance requirements, and (c) the licensee provided documentation showing that the NRC's review of other licensing actions has determined that the use of Areva's BWSPAN and SYSNUKE is acceptable. This minor violation is not subject to enforcement action in accordance with Section 2.3.1 of the NRC Enforcement Policy, dated February 4, 2015. The UFSAR for Unit 1 did not describe the computer programs used for the structural design of the original SGs; therefore, this issue applies to Unit 2 only.

4OA3 Follow-up of Events and Notices of Enforcement Discretion

(Closed) Licensee Event Report (LER) 05000389/2015-002-00, 2A Emergency Diesel Generator Actuation Logic

On September 17, 2015 with Unit 2 shutdown and Unit 1 operating at 100 percent RTP, an electrical fault on the 2A1 6.9 kV bus resulted in the loss of the 1A and 2A SUTs. The fault resulted in a loss of power to safety-related bus 2A3 and actuation of the bus under voltage relays that would have started the 2A EDG. The 2A EDG did not start because it had been removed from service for planned maintenance, as allowed by TSs. The Unit 1 safety-related bus 1A3 was not impacted because it was powered by an auxiliary transformer, which is the normal electrical lineup for an operating unit. The inspectors' review of the root cause associated with this event is documented in Section 4OA5. An NCV associated with the untimely 10 CFR 50.72 notification of the 2A EDG Actuation Logic was previously documented in NRC Integrated Inspection Report 05000335/2015003, 05000389/2015003 (ADAMS Accession Number ML15309A146). No additional findings were identified. This LER is closed.

4OA5 Other Activities

(Closed) Unresolved Item 05000335, 389/2015003-02, Partial Loss of Unit 1 and Unit 2 Offsite Power Due to Unit 2 6.9 kV Non-Segregated Bus Fault

Unresolved item URI 05000335, 389/2015003-02, "Partial Loss of Unit 1 and Unit 2 Offsite Power Due to Unit 2 6.9 kV Non-Segregated Bus Fault," was opened in NRC Integrated Inspection Report 05000335/2015003, 05000389/2015003 (ADAMS Accession Number ML15309A146) pending a review to determine whether or not a performance deficiency existed.

On September 17, 2015, a fault of the 2A1 6.9 kV bus connected to the 2A SUT resulted in the loss of offsite power (LOOP) to both the 1A and 2A SUTs. The 1A SUT was impacted because it shared a common power supply from the switchyard with the 2A SUT. The 2A 6.9kV bus is made up of flat copper bars that are bolted together with all three phases contained in a metal enclosure. The phases are supported within the enclosure and insulated from each other using ceramic insulator plates that maintain the spacing between the phases and the enclosure. Rubber insulating boots cover the bolted connections. The licensee's inspection of the 6.9 kV bus determined that the fault occurred at a location where the bus transitions from a vertical to a horizontal orientation. The three insulating boots for this bolted transition were found lying on top of the ceramic insulators between the phases below the vertical run. The boots had a coating of dust and corrosion products that had flaked off the enclosure. The licensee entered this issue in the CAP as AR 2074774.

The Licensee's root cause evaluation (RCE) determined that the protective rubber boots for a bus bar bolted connection, at a vertical riser section, were not installed properly during plant construction (circa 1979). Over time, contaminates built up on a boot between the "B" and "C" phases, creating a fault path between the phases.

The inspectors verified the adequacy of the licensee's corrective actions completed, which included inspections, repairs as necessary, and testing of the faulted 2A1 6.9 kV and the 2B1 6.9 kV non-segregated buses prior to the Unit 2 startup from the RFO. In addition, the licensee will perform a 100 percent internal visual inspection of the remaining 6.9 kV and 4.16 kV non-segregated bus vertical riser sections to ensure that all bolted connections have properly installed protective boots.

The inspectors observed maintenance activities associated with the restoration of the 2A1 6.9 kV bus, as well as test data to verify the condition of the bus was acceptable to place it back in service. As-left test data for the 2B1 6.9 kV bus was also reviewed.

The inspectors also reviewed the circumstances and corrective actions associated with a similar partial LOOP event that impacted both units, which occurred on October 3, 2012, to determine whether those corrective actions should have precluded the September 2015 partial LOOP event. In October 2012, a partial LOOP was experienced when a fault developed across two phases of the 2B1 6.9 kV bus when a corroded non-segregated bus duct vent screen fell on top of the bus bars. The inspectors documented a Green self-revealing finding for the licensee's failure to establish adequate preventative maintenance (PM) activities for the 6.9 kV non-segregated bus for both units. This finding and additional details are documented in NRC Integrated Inspection Report 05000335/2013004, 05000389/2013004 (ADAMS Accession Number ML13302C066). Corrective actions included: replacement of the corroded non-segregated bus duct vent associated with the event; updating the PM program to address periodic maintenance of non-segregated bus duct vents, and; completion of inspections and repairs, as necessary, of the outdoor bus duct vents for bus runs to the SUTs and auxiliary transformers on both units. The licensee has begun planning long term corrective actions to replace the non-segregated buses on both units with electrical cable.

The licensee relied on the work control program to implement PMs for internal inspections of the non-segregated buses. The PM established for each bus did not include a 100 percent inspection of the internals of the bus. The scope of the PM was determined by engineering. The licensee relied, in part, on non-intrusive electromagnetic interference (EMI) testing results in determining when to schedule the preventative maintenance. On September 7, 2015, EMI testing of the 2A1 6.9 kV bus was completed. The vendor EMI report concluded that there was no need for immediate corrective actions for the bus. As a result, the PM for the 2A1 6.9 kV bus was deferred until after the RFO. The bus experienced a fault on September 17, 2015. The 2015 RCE investigation determined that the station's decisions regarding non-segregated bus PMs overly relied on EMI testing results and did not recognize its limitations.

In conclusion, the improperly installed insulating boots could not have independently caused the most recent bus failure, as evidenced by the fact that they were likely in that location for 35 years with no related failures. Furthermore, internal inspections planned as a result of the 2012 event would not have unequivocally identified the corrosion products in the affected area of the 2015 event due to the relevant size and confinement of the bus. Based on these facts, the inspectors did not identify a performance deficiency during the inspection. This URI is closed.

4OA6 Meetings

Exit Meeting Summary

The resident inspectors presented the inspection results to Mr. Costanzo and other members of licensee management on January 14, 2016. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary information. The licensee did not identify any proprietary information.

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 the NRC Enforcement Policy for being dispositioned as NCVs.

.1 10 CFR55.49, "Integrity of examinations and tests," states, "Applicants, licensees, and facility licensees shall not engage in any activity that compromises the integrity of any application, test, or examination required by this part. The integrity of a test or examination is considered compromised if any activity, regardless of intent, affected, or, but for detection, would have affected the equitable and consistent administration of the test or examination. This includes activities related to the preparation and certification of license applications and all activities related to the preparation, administration, and grading of the tests and examinations required by this part." Contrary to the above, on August 18, 2015, the licensee identified that two licensed operators were administered a 2014 biennial requalification comprehensive written examination that contained five repeat questions from other versions of the biennial written examination that the individuals had either prepared or approved. The inspectors determined that the violation was not greater than very low safety significance (Green) because the licensed operators were not actively performing licensed duties in the control room. This issue was entered in the licensee's corrective action program as CR 02067887.

.2 Contrary to TS 6.8.1, "Procedures and Programs," the licensee failed to implement the written procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, dated February 1978, regarding PM of safety-related equipment. Specifically, Regulatory Guide 1.33 Appendix A Section 9.b states, in part, that system parts that have a specific lifetime should be replaced. The licensee implements this guidance in Regulatory Guide 1.33 by following the PM program, ER-AA-204, "Preventive Maintenance Program Strategy," Revision 5, which details how PM should be developed and implemented for safety-related equipment. Section 3.2.9 of this procedure states, in part, that to ensure inclusion of vendor technical information, vendor maintenance recommendations should be included in PM bases and frequency requirements. The ESI-EMD owners group recommends a 10-year life for EDG speed switches based on electrolytic capacitor life expectancy. However, there is no evidence that the licensee considered vendor recommendations regarding the periodicity of EDG speed switch replacement when implementing its PM on the EDG. As a result, the existing PM for the speed switches was inadequate and led to the 1A EDG being rendered inoperable when the speed switch failed to function properly during manual local start of the EDG. This violation was associated with the Mitigating Systems Cornerstone and was determined to be of very low safety significance (Green) in accordance with Manual Chapter 0609 Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," because the finding did not result in a loss of system function or represent an actual loss of function of at least a single train for greater than its TS allowed outage time. The licensee entered this violation into its CAP as AR 2053060.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
G. Alexander, Supervisor Fleet Programs Engineering
R. Baird, Acting Training Manager
D. Cecchett, Licensing Engineer
B. Coffey, Plant General Manager
C. Costanzo, Site Vice President
W. Cross, Fleet Regulatory Programs Manager
E. Feightner, ILT Supervisor
K. Frehafer, Licensing Engineer
R. Gil, Steam Generator Program Manager
D. Griffin, Boric Acid Program Owner
M. Haskin, Projects Site Manager
M. Jones, Engineering Director
E. Katzman, Licensing Manager
E. Korkowski, Corporate SG Program Manager
C. Martin, Health Physics Manager
R. McDaniel, Fire Protection Supervisor
C. Montana, Work Control Manager
T. Ouret, Fleet Operations Training Manager Corporate
J. Owens, Operations Training Supervisor
W. Parks, Operations Director
D. Pitts, Maintenance Director
R. Sciscente, Licensing Engineer
M. Snyder, Nuclear Quality Assurance Manager
C. Spenser, Chemistry Manager
T. Spillman, Assistant Operations Manager–Training
C. Workman, Security Manager

NRC personnel:
LaDonna B. Suggs, Chief, Branch 3, Division of Reactor Projects
Rogerio Reyes, NRC Resident Inspector

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000335, 389/2015004-01	FIN	NRC Biennial Written Examinations Did Not Meet Qualitative Standards (Section 1R11.4)
05000335, 389/2015004-02	NCV	Non-willful Compromise of a Remedial Examination Required by 10 CFR 55.59 Affected the Equitable and Consistent Administration of the Exam (Section 1R11.4)
05000335, 389/2015004-03	NCV	Inadequate Corrective Actions to Prevent Fouling of the CCW HXs (Section 4OA2.3)
05000335, 389/2015004-04	NCV	Procedural Non-compliances Relating to Installed Scaffold Located Near Safety-related SSCs (Section 4OA2.4)
05000335, 389/2015004-05	NCV	Failure to Verify the Adequacy of the Unit 1 and Unit 2 Steam Generator Tube-to-Tubesheet Welds Design (Section 4OA2.5)

Closed

05000335, 389/2014005-02	URI	Design Basis Review for the Unit 1 and Unit 2 Steam Generator Tube-to-Tubesheet Joint (Section 4OA2)
05000389/2015-002-00	LER	2A Emergency Diesel Generator Actuation Logic (Section 4OA3)
05000335, 389/2015003-02	URI	Partial Loss of Unit 1 and Unit 2 Offsite Power Due to Unit 2 6.9 kV Non-Segregated Bus Fault (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

<u>Section 1R04 Equipment Alignment</u>

2-NOP-14.01, Component Cooling Water System Initial Alignment
2-NOP-59.01A, 2A Emergency Diesel Generator Standby Alignment
2-NOP-09.11, Auxiliary Feedwater System Initial Alignment
Drawing 2998-G-083, Unit 2 Flow Diagram Component Cooling Water System
System Health Report: CCW system dated October 27, 2015

<u>Section 1R05 Fire Protection</u>

ADM-0005729, Fire Protection Training, Qualification and Requalification
ADM-1800022, Fire Protection Plan
AP-1-1800023, Unit 1 Fire Fighting Strategies
AP-2-1800023, Unit 2 Fire Fighting Strategies

<u>Section 1R08 In-service Inspection Activities</u>

<u>Pocedures</u>:

03-9219485, St. Lucie (PSL) Unit 2 Eddy Current Data Analysis Guidelines September 2015, Rev. 001
54-ISI-400, Multi-Frequency Eddy Current Examination of Tubing (AREVA), Rev. 021
DM-29.03, Boric Acid Corrosion Control Program, Rev. 14
ENG-CSI 2.3, Steam Generator Integrity Program Administration, Rev. 32
ER-AA-111-1000, Flow Accelerated Corrosion (FAC) Activities
ER-AP-121, Steam Generator Integrity, Rev. 1
NDE 2.2, Magnetic Particle Examination, Rev. 15
NDE 3.3, Liquid Penetrant Examination Solvent Removable Visible Dye Technique, Rev. 13
NDE 4.2, Visual Examination VT-2 Conducted During System Pressure Test, Rev. 11
NDE 4.3, Visual Examination VT-3, Rev. 12
NDE 4.7, Visual Examination of Reactor Building Containment Vessel General Visual/Detailed Visual (VT-1/VT-3)(IWE), Rev. 11
NDE 5.1, Ultrasonic Examination of Pressure Vessel Welds, Rev. 13
NDE 5.4, Ultrasonic Examination of Austenitic Piping Welds, Rev. 20
NDE 5.8, Straight Beam Ultrasonic Examination of Bolts and Studs, Rev. 11
NDE 5.18, Ultrasonic Thickness Measurement, Rev. 8
PI-AA-104-1000, Corrective Action, Rev. 5
STD-W-001, Administrative Requirements for the Welding Control Manual, Rev. 5
STD-W-002, General Welding Standards Safety Related Piping, Rev. 14

<u>Drawings</u>:

2998-G-078, Sheet 110, Flow Diagram for Reactor Coolant System, Rev. 13
2998-CW-3000-77, Sheet 1,2, 3, Circulation Water, Rev. 11
02-005-A, Pressurizer, Rev. 8
PSL-2-13, Checmate Erosion Corrosion Program, Rev. 2

<u>Self-Assessments</u>:

SAR#1837244, Self Assessment, BACCP, 2013
AR#1858601, Self Assessment, ISI, FAC, 2013
Report#PSI-12-005, Self Assessment, Welding, 2012

Work Orders/Work Requests:
40321125, V2464 Isolation Valve for Charging Pump 2B, 2015
40342491-05, VT-3 of Moisture Barrier, 2015
4035174 5, V3664 MOV Loop 2A SDS RTN LPSI PP 2A, 2015

New Condition Reports Generated
AR 2074255, NRC Observation Boric Acid Leaks Not Repaired
AR 2074008, NRC Observation BACC Evaluation Template Not Proceduralized
AR 2073916, NRC Observation Boric Acid Leaks Not Repaired in Timely Manner
AR 2074947, Evaluate of Unit 1 RR#9 and Unit 2 RR#4 should be withdrawn

Condition Reports
1908552, BAC Trying Implemented Inconsistently Across the Fleet
1983808, V3461 Active BA Seat Leak
2013791, V6184 Active BA Bonnet Leak
1972693, V2595 Active BA Bonnet Leak
2068416, V2343 Active BA Leak at Packing
2075128, V1475 Active BA Leak at Inlet Package
2075125, V1474 Active BA Leak at Inlet Package
2074364, IWF Visual Examination Support CW-3000-77 on Line I-30-CW-9
2059432, RR#9 for Unit 1's 4th 10 year ISI Interval was submitted late to the NRC
1773978, Welder Credit for Weld Activity Performed Offsite
1984196, Weld Inspection Criterion Not Included in Traveller
2024631, NDE Alert Letter – Industry Actions for ASME XI UT of Bolting

Welder Quals:
Record of Welder Performance Qualification Test – P. Merryman, C. King, C. Felie, and T. Sunny

Visual Acuity Exam Record:
J. Kilpela, T. Coburn, M. Johnson, J. Gatica, J. Timm, and D. Nowakowski

Certificate of Qualification for NDE Examiner:
R. Kimmer, W. Marquardt, J. Kilpela, T. Coburn, M. Johnson, J. Gatica, J. Timm, and D. Nowakowski

Miscellaneous Documents:
51-9247161-000, AREVA St. Lucie Unit 2 SG B Feed Water Ring Operability Assessment, Rev. 000
AES 15048843-2-1, Intertek Degradation Assessment for St. Lucie Unit 2 Steam Generators for End-of-Cycle 21 (September 2015 Outage), Rev. 1
Anatec Personnel Certification Summary Record: ET (Lucier), dated August 9, 2013
AREVA Certificate of Personnel Qualification: ET (Bowyer), dated June 18, 2015
AREVA Certificate of Personnel Qualification: ET (Keyes III), dated January 29, 2015
AREVA Certificate of Personnel Qualification: ET (Vouyioukas), dated July 25, 2013
AREVA Certificate of Vision Examination (Bowyer), dated June 11, 2015
AREVA Certificate of Vision Examination (Keyes III), dated August 18, 2015
AREVA Certificate of Vision Examination (Vouyioukas), dated August 5, 2015
Curtiss-Wright Vision Examination Certification (Lucier), dated April 17, 2015
INETEC Certificate of Vision Examination (Križanac), dated March 31, 2015
INETEC NDT Personnel Certification Record: ET (Križanac), dated March 10, 2015

Report #CSI-FAC-PSL-2-22-D, Component#12ES2-P-7-15, Extraction Steam from HPT to SBFW Heater
Report #CSI-FAC-PSL-2-22-P, Component#14C83-P-28-60, Heater Drain Back to Condensate, System
Welding Procedure 43, 87
Welding Procedure Qualification Record N140, N258, N334, N334, 8.8-4, and 8.8-3

Section 1R11 Licensed Operator Requalification Program and Licensed Operator Performance

2-AOP-09.03, Secondary Chemistry
2-AOP-22.01, Rapid Downpower
1-AOP-22.01, Rapid Downpower
1-AOP-66.01, Dropped or Misaligned CEA Abnormal Operations

Records:
License Reactivation Packages (6 records reviewed)
LORP Training Attendance records (9 records reviewed for Shift 3)
License Maintenance Records (9 records reviewed for Shift 3)
Medical Files (7 records reviewed)
Remedial Training Records (15 remediation packages)

Written Examinations:
2014 Biennial Written RO and SRO Exam, 082014EA
2014 Biennial Written RO and SRO Exam, 082014EB

Condition Reports (CR):

02067887	01938053	01997235
02069159	01942977	02034088
02069162	02062871	02060034
02069164	02050745	02081863
02069184	01943664	
01925464	01969325	
01929101	01978021	
01935621	01978323	
01937255	01978651	

Procedures:
TR-AA-220-1004 rev. 1, Licensed Operator Continuing Training Annual Operating and Biennial Written Exams
TR-AA-220-1002 rev. 1, NRC Licensed Operator Exam Security
TR-AA-230-1003 rev. 2, SAT Development
TR-AA-230-1004 rev. 5, SAT Implementation
TR-AA-230-1004 rev. 2, Conduct of Simulator Training and Evaluation
TR-AA-230-1008 rev. 1, Simulator Scenario Based Testing and Validation
TR-AA-104 rev. 6, NEXTERA ENERGY Fleet Licensed Operator Continuing Training Program

Simulator Tests/Records:
SST-002 rev. 4, Steady State at Power Level Hold Points, performed on 12/9/14
TRN-001 rev. 10, Reactor Trip, 12/9/14.

TRN-002 rev. 10, Loss of Main Feedwater Pump from 100% Power with Failure of ALL Emergency Feedwater, 12/19/14.
TRN-003 rev. 9, Simultaneous Closure of Both Main Steam Isolation Valves, 12/20/14.
TRN-004 rev. 8, Loss of All RCPs from Full Power, 12/20/14.
TRN-005 rev. 7, Loss of 1 RCP From 100% Full Power, 12/20/14.
TRN-006 rev. 10, Turbine Trip From <15% Power (No Rx Trip), 12/21/14.
TRN-007 rev. 9, Maximum Rate Power Ramp (100% to approximately 75%), 12/23/14.
TRN-008 rev. 9, Large Break LOCA with Loss of Offsite Power, 12/21/14
TRN-009 rev. 9, Double Ended Main Steam Line Break Inside Containment, 12/21/14.
TRN-010 rev. 7, One Failed Open Pressurizer Safety Valve Which Depressurizes RCS To A Saturated Condition Without HPSI, 12/21/14.
Plant St. Lucie simulator I/O replacement project 2015 Site Acceptance Test records
Simulator performance comparison to actual Unit 2 manual Rx trip on 11/12/14 at 1548
Post trip review procedure 0030119 Rev. 52, performed 11/12/14 through 11/18/14

<u>Simulator Scenario Packages</u>:
Simulator Exercise Guide 0815006.r21
Simulator Exercise Guide 0815015.r13
Simulator Exercise Guide 0815018.r19
Simulator Exercise Guide 0815020r.21

<u>Job Performance Measure Packages</u>:
PSL OPS 0821009A.r11
PSL OPS 0821014A.r12
PSL OPS 0821112T.r12
PSL OPS 08210064.r18
PSL OPS 0821143.r7
PSL OPS 0821026A.r16
PSL OPS 0821084.r17
PSL OPS 0821114.r16
PSL OPS 0821033.r19
PSL OPS 0821067.r19

Section 1R12 Maintenance Effectiveness
ER-AA-100-2002, Maintenance Rule Program Administration
SCEG-004, Guideline for Maintenance Rule Scoping, Risk Significant Determination, and Expert Panel Activities

Section 1R13 Maintenance Risk Assessments and Emergent Work Control
OP-AA-104-1007, Online Aggregate Risk
WCG-016, Online Work Management
ADM-09.23, Outage Risk Assessment and Control
OM-AA-101-1000, Shutdown Risk Management

Section 1R15 Operability Determinations and Functionality Assessments
EN-AA-203-1001, Operability Determinations and Functionality Assessments

<u>Calculations</u>
AREVA Document No. 32-9236026-000, St. Lucie SG 2B Hot Leg Primary Side Components Re-evaluation for Continued Operation, Rev. 0
AREVA Document No. 32-9240251-000, St. Lucie Unit 2 SG-B Primary Side Loose Part

Damage Fracture Analysis, Rev. 0
AREVA Document No. 51-9239843-000, Engineering Information Record - St. Lucie 2 Divider Plate Evaluation, Rev. 0
AREVA Document No. 51-9240977-001, Test Results of Damaged .750 Rolled Plugs, Rev. 1
AREVA Document No. 51-9244464-000, Evaluation of St. Lucie Unit 2 Steam Generator B Integrity Due to Primary Loose Parts Damage – Summary Report, Rev. 0

Corrective Action Documents
AR 01955927, Channels 7 and 8 Alarming, 4/8/2014
AR 01957565, Foreign Material Discovered in 2B Hot Leg Steam Generator, 4/12/2014
AR 02011678, Design Basis Review for Steam Generator Tubesheet Design, 12/8/2014

Section 1R20 Refueling and Other Outage Activities
2-GOP-302, Reactor Plant Startup – MODE 3 TO MODE 2
OP-AA-102-1003, Guarded Equipment
ADM-09.23, Outage Risk Assessment and Control
0-NOP-67.05, Refueling Operation
2-NOP-67.04, Refueling Operation
2-NOP-01.04, RCS Reduced Inventory and Mid-Loop Operation
ADM-09.14, Reduced Inventory / Mid-Loop

Section 1R22 Surveillance Testing
ADM-29.02, ASME Code Testing of Pumps and Valves
OP-AA-200, Surveillance Frequency Change Process
NEI 04-10, Risk-Informed Method for Control of Surveillance Frequencies
CR 2022479, Surveillance Test Interval (STI) Change Evaluation Form
Licensee training database for Maintenance Rule and Integrated Decision-Making Panel (IDP) members
WO 40417654, 2A HSPI Pump Retest for Failure to Start
AR 2081028, Assignment 2, Unit 2 Train A ESFAS Test Anomaly

Section 4OA2: Identification and Resolution of Problems
Engineering Change EC-279344, Eliminate Mid-Cycle CCW Heat Exchanger Cleaning
0-NOP-40.01, Hypochlorite System Operation
0-NOP-40.02, Auxiliary Hypochlorite System Operation
2-OSP-100.27, Schedule of Periodic Tests, Checks and Calibrations
CY-SL-104-2222, Unit 2 Closed Cooling Water System Sampling
CY-SL-102-0008, Determination of Chlorine Using Hach Pocket Colorimeter
0-COP-05.04, Chemistry Department Surveillances and Parameters
0-PMM-14.01, Component Cooling Water Heat Exchanger Clean / Repair
2998-G-092, Flow Diagram Hypochlorite System
St. Lucie Chemistry Standing Order 2015-016, ICW Chlorine Contingency Actions
Chemistry Self-Evaluation and Trending Analysis Report- 3rd Quarter 2015
Engineering Self-Evaluation and Trending Analysis Report- 3rd Quarter 2015
Maintenance Self-Evaluation and Trending Analysis Report- 3rd Quarter 2015
Operations Self-Evaluation and Trending Analysis Report- 3rd Quarter 2015
Security Self-Evaluation and Trending Analysis Report- 3rd Quarter 2015
Station Self-Evaluation and Trending Analysis Report- 3rd Quarter 2015
Training Self-Evaluation and Trending Analysis Report- 3rd Quarter 2015
Work Control Self-Evaluation and Trending Analysis Report- 3rd Quarter 2015

Corrective Action Documents

AR 02011678, Design Basis Review for Steam Generator Tubesheet Design, 12/8/2014
AR 02007665, Track Update to Wording Used in Areva PSL2 RSG Report, 11/18/2014
AR 02035185, PSL1 Steam Generators Tube-To-Tubesheet Design, 12/23/2015
AR 01688957, Develop St. Lucie Specific GL 89-13 Documents
AR 01964549, Low Chlorine Values In Intake Cooling Water System
AR 02002575, Replace Sodium Hypochlorite System
AR 02034680, The Hypochlorite System Has No Flow
AR 02034892, Can Not Obtain Any Hypo Flow To ICW Wells
AR 02035649, Minimal Hypo Leak Found
AR 02035917, Hypochlorite Piping Clogged
AR 02076834, ICW Total Residual Chlorine samples were not logged in Nuclear IQ from 1/20/15 to 6/18/15
AR 02078384, Failure to complete Generic Letter 89-13 Unit 2 ICW piping inspection Commitment date of 10/30/15
AR 02089161, Limited Hypochlorite Injection to ICW/CW
AR 02092033, Sodium Hypochlorite System Effectiveness Review
AR 02092663, Chlorine QC Checks Not Consistently Recorded
AR 02092669, No Chlorine Residual Detected on 2A CCW HX
AR 02092674, No Acceptance Criteria in Procedure for Chlorine
AR 02092681, Hypochlorite Addition to ICW System not Continuous
AR 02092721, Determine If the Hypochlorite System should be in the Scope of License Renewal

Procedures

PI-AA-104-1000, Corrective Action, Rev. 1

Other Documents

Areva Document 32-9235210-001, Stress Analysis of Tube-Tubesheet Weld – Areva RSG,
Areva Document 51-5056942-001, St. Lucie Unit 2 RSG SER Review, Rev. 1
Areva Document 51-9000949-003, St. Lucie Unit 2 RSG Condensed UFSAR Review, Rev. 3
Areva Document No. 77-5069878-004, Replacement Steam Generator Report for Florida Power and Light, St. Lucie Unit 2, Rev. 4, 12/18/2015
AREVA-15-00402, Final Deliverable Submittal for Review Replacement Steam Generator 50.59 Re: Tube sheet Weld Design, 2/13/2015
BWXT Document 314Q-B001, St. Lucie Replacement Steam Generator Tube-to-Tubesheet Weld Primary Stress Analysis, Rev. 0
BWXT Document 314Q-B002, Engineering Calculation, St. Lucie Replacement Steam Generators Tube-To- Tubesheet Weld Test, Level A & B And Fatigue Analysis, Rev. 0
Certified Design Specification No. F-MECH-SP-002, Engineering Specification for Replacement Steam Generator Assemblies for Florida Power and Light Co. – St. Lucie Unit 1, Rev. 3
Guidance for Performing 10 CFR 50.59 Evaluations, May 13, 2001
JPN-PSL-SENP-94-026, St. Lucie Nuclear Plant Unit 1 - Stand Alone Safety Evaluation Steam Generator Equivalency Report, 6/3/1997, Rev. 1
SGRP-SPEC-M-009, Certified Design Specification for Replacement Steam Generators St. Lucie Unit No. 2, Rev. 2, April 2007
Updated Final Safety Analysis Report for St. Lucie Plant, Unit 2, Amendment 17
Oconee Nuclear Station, Units 1, 2, and 3, Re: Reactor Coolant Loop Analysis Methodology for Steam Generator Replacement, dated September 6, 2001, ADAMS Accession Number ML012490111

LIST OF ACRONYMS

ADAMS	NRC's Agency-wide Documents Access and Management System
AFW	Auxiliary Feedwater
AP	Administrative Procedure
AR	Action Request
AC	Alternating Current
ACE	Apparent Cause Evaluation
ASME	American Society of Mechanical Engineers
BA	Boric Acid
BACC	Boric Acid Corrosion Control
BPVC	Boiler and Pressure Vessel Code
CAP	Corrective Action Program
CCW	Component Cooling Water
CEA	Control Element Assembly
CFR	Code of Federal Regulations
CIS	Containment Isolation System
CR	Condition Report
CSAS	Containment Spray Actuation System
CST	Condensate Storage Tank
DBA	Design Basis Accident
DC	Direct Current
DFS	Debris Filter System
DOST	Diesel Oil Storage Tank
DPM	Drop per Minute
EC	Engineering Change
ECT	Eddy Current Test
EDG	Emergency Diesel Generator
EMI	Electromagnetic Interference
EP	Emergency Preparedness
EPIP	Emergency Plan Implementing Procedure
EPRI	Electric Power Research Institute
EPU	Extended Power Uprate
ESI-EMD	Engine Systems Inc – Electro-Motive Diesel
ETSSs	Examination Technique Specification Sheets
FPL	Florida Power and Light
FS	Fire Sytem
GOP	General Operating Procedure
HPSI	High Pressure Safety Injection
HX	Heat Exchanger
IMC	Inspection Manual Chapter
ICW	Intake Cooling Water
IP	Inspection Procedure
ISI	In-Service Inspection
JPM	Job Performance Measure
kV	Kilovolt
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPSI	Low Pressure Safety Injection
LTAM	Long Term Asset Management

MFIV	Main Feedwater Isolation Valve
MR	Maintenance Rule (10 CFR 50.65)
MT	Magnetic Testing
MV	Motor Valve
NCV	Non-Cited Violation
NDEs	Non-destructive Examinations
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
OCC	Outage Command Center
OE	Operating Experience
OLRM	Online Risk Monitor
OOS	Out-of-Service
OSP	Operations Surveillance Procedure
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PM	Preventative Maintenance
PSIG	Pounds per Square Inch Gauge
PSIA	Pounds per Square inch Absolute
PSL	St. Lucie Plant
PT	Penetrant Testing
PTP	Preoperational Test Procedure
PWR	Pressurized Water Reactor
QA	Quality Assurance
RCB	Reactor Containment Building
RCE	Root Cause Evaluation
RCS	Reactor Coolant System
RFO	Refueling Outage
RSG	Replacement Steam Generator
RTP	Rated Thermal Power
RWT	Refueling Water Tank
SDP	Significance Determination Process
SFP	Spent Fuel Pool
SG	Steam Generator
SH	Sodium Hypochlorite
SIAS	Safety Injection Actuation System
SLIV	Severity Level IV
SR	Surveillance Requirement
SSA	Shutdown Safety Assessment
SSC	Structure, System, and Component
SUT	Startup Transformer
TSs	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Testing
VT	Visual Testing
WO	Work Order
WR	Work Request