UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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ATLANTA, GEORGIA 30303-1257

January 29, 2018

Mr. Mano Nazar
President and Chief Nuclear Officer
Nuclear Division
Florida Power & Light Co.
Mail Stop: EX/JB
700 Universe Blvd.
Juno Beach, FL 33408

SUBJECT: ST. LUCIE PLANT – NUCLEAR REGULATORY COMMISSION INTEGRATED INSPECTION REPORT 05000335/2017004 AND 05000389/2017004

Dear Mr. Nazar:

On December 31, 2017, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your St. Lucie Plant Units 1 and 2. On January 11, 2018, the NRC inspectors discussed the results of this inspection with Mr. DeBoer and other members of your staff. The results of this inspection are documented in the enclosed report.

NRC inspectors documented three findings of very low safety significance (Green) in this report. The findings involved violations of NRC requirements. Further, the inspectors documented a licensee-identified violation that was determined to be of very low safety significance in this report. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2.a of the Enforcement Policy.

If you contest the violations or significance of the NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator Region II; the Director, Office of Enforcement; and the NRC resident inspector at the St. Lucie Plant.

If you disagree with the 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 U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; and the NRC resident inspector at the St. Lucie Plant.

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and at the NRC Public Document Room in accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding."

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 05000335/2017004 and 05000389/2017004
w/Attachment: Supplemental Information

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REGION II

Docket Nos:	50-335, 50-389
License Nos:	DPR-67, NPF-16
Report Nos:	05000335/2017004, 05000389/2017004
Licensee:	Florida Power & Light Company (FPL)
Facility:	St. Lucie Plant, Units 1 and 2
Location:	6501 South Ocean Drive Jensen Beach, FL 34957
Dates:	October 1, 2017 through December 31, 2017
Inspectors:	T. Morrissey, Senior Resident Inspector S. Roberts, Resident Inspector D. Bacon, Senior Operations Engineer (Section 1R11.4) P. Capehart, Senior Operations Engineer (Section 1R11.3) D. Lanyi, Senior Operations Engineer (Section 1R11.4) J. Orr, Senior Resident Inspector Turkey Point (Section 4OA2.3) G. Ottenberg, Senior Reactor Inspector (Sections 1R17, 4OA3.4) R. Patterson, Reactor Inspector (Sections 1R17, 4OA3.4)
Approved by:	LaDonna B. Suggs, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

SUMMARY

IR 05000335/2017004, 05000389/2017004; 10/01/2017 – 12/31/2017; St. Lucie Nuclear Plant, Units 1 and 2; Followup of Events and Notices of Enforcement Discretion.

The report covered the three-month period of inspection from October 1, 2017, to December 31, 2017. The inspection activities were performed by the resident inspectors and region based specialist inspectors. Two self-revealing and one NRC-identified Green non-cited violations (NCVs) were documented during this inspection period. The significance of inspection findings are indicated by their color (Green, White, Yellow, or Red) and determined using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process,” (SDP) dated April 29, 2015. The cross-cutting aspect was 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 November 1, 2016. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 6.

NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A Green, self-revealing NCV of 10 Code of Federal Regulations (CFR) Part 50, Appendix B, Criterion V, “Instructions, Procedures and Drawings,” was identified for the licensee’s failure to have an adequate procedure for reducing the trip setpoint of the “B” channel of the reactor protection system (RPS) high startup rate (HSUR) bistable. The licensee’s failure to establish an adequate procedure, as required by 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” to place the "B" channel wide range nuclear instrument in a tripped condition was a performance deficiency (PD). This deficiency resulted in a violation of Technical Specification (TS) Limiting Condition for Operation (LCO) 3.3.1.1. Following discovery of the condition, the licensee initiated immediate corrective actions to place the “B” channel RPS HSUR in trip, meeting the TS requirement.

  The inspectors determined that the finding was more than minor because it was associated with the Mitigating Systems cornerstone attribute of procedural quality and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, there was no procedure to perform the setpoint reduction method as identified in 1-AOP-99.01. The only direction was to “Contact I&C” in the step. The Instrumentation and Control (I&C) processes used to implement the HSUR reduced setpoint reduction method were inadequate, in that, they did not evaluate all potential failure conditions when setting the HSUR bistable. The finding did not screen as greater than Green because while the degradation affected a single RPS trip signal, it did not affect the function of other redundant trips; and the finding did not involve control manipulations that unintentionally added positive reactivity; and finally the finding did not result in a mismanagement of reactivity by operators. Using IMC 0310, “Aspects Within the Cross-Cutting Areas,” the inspectors determined that the finding had a cross-cutting aspect in the area of human performance. Specifically, the cross-cutting aspect of resources (H.1) was assigned to the finding because the licensee did not ensure an adequate procedure was available to implement the HSUR setpoint reduction. (Section 4OA3.2)

- Green. A Green, self-revealing, NCV of TS 6.8.1 was identified for the licensee's failure to adequately implement a maintenance procedure during a monthly flow channel check for the 2C Auxiliary Feedwater (AFW) pump. Specifically, the licensee failed to implement as-written surveillance maintenance procedure 2-SMI-09.05C, "2C Auxiliary Feedwater Pump Flow Channel Check," when performing the channel checks for both 2C AFW pump flow transmitters. The licensee's failure to follow surveillance maintenance procedure 2-SMI-09.05C, was a PD. Upon discovery, the flow transmitters were declared inoperable and subsequently, the condition was promptly restored to normal.

  The PD was more than minor because it was associated with the Human Performance attribute of the Mitigating Systems cornerstone and it adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The PD adversely affected the licensee's ability to monitor 2C AFW flow during a design basis accident. The inspectors determined that the finding was not greater than Green because it did not represent a deficiency affecting the design or qualification of a mitigating system; it did not represent a loss of system and/or function; it did not represent an actual loss of function for at least a single train for more than its TS allowed outage time; and it did not represent an actual loss of function of one or more non-TS trains of equipment designated as high safety-significant in accordance with the licensee's maintenance rule program. The finding involved the cross-cutting area of human performance, with an aspect of avoiding complacency (H.12), in that, the licensee failed to ensure that personnel effectively used human performance tools during the AFW pump flow channel check to ensure procedure steps were completed as required. (Section 4OA3.3)

- Green. The NRC-identified a Green non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, for failure to identify and correct a condition adverse to quality. The licensee failed to identify that their procedures lacked actions to install control power jumpers that are required to defeat the reactor coolant systems (RCS) pressure interlocks for the shutdown cooling (SDC) suction line motor operated valves (MOVs) when aligning the plant for hot leg injection (HLI) and then correct the condition. Following the identification of this procedural vulnerability, the licensee fabricated control power jumpers and revised procedure 1-GME-100.03, "Installation and Removal of Temporary Power Jumpers for MOV V3481, V3652, V3432 AND V3444," to provide direction for installation of power jumpers. In addition, the licensee performed a more detailed failure modes and effects analysis to ensure that the revised procedures accounted for all possible single failures. This issue has been entered into the licensee's corrective action program (CAP) as CR 2217631.

  The PD was more than minor because it was associated with the Design Control attribute of the Mitigating System cornerstone objective of ensuring the capability of the low pressure safety injection (LPSI) system to perform its required long term cooling safety function (HLI). The condition was evaluated by a Regional Senior Reactor Analyst and determined to have very low safety significance (Green) based on the low likelihood of a loss of coolant accident (LOCA) and low likelihood of electrical failures requiring jumpers to be installed. This issue and corrective actions were documented in the licensee's CAP as Action Request (AR) 2217631. This finding was not assigned a cross-cutting aspect because the underlying cause was a legacy issue and not indicative of current performance. (Section 4OA3.4)

Licensee-Identified Violations

One violation of very low safety significance (Green), which was 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 (CAP). 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 was at 100 percent rated thermal power (RTP) during the inspection period.

Unit 2 began the inspection period at 100 percent RTP. On October 11, 2017, power was lowered to approximately 81 percent RTP in order to perform planned semi-annual turbine valve testing. Unit power was returned to 100 percent RTP later that day. On October 26, 2017, the unit automatically tripped from 100 percent RTP due to an equipment problem with the main generator digital electrohydraulic (DEH) control system. The DEH system was repaired and the unit was restarted on October 28, 2017 and returned to 100 percent RTP on October 29, 2017. The unit was at 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection (IP 71111.01)

Readiness for Seasonal Winter Weather Conditions

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the station's cold weather preparations as described in licensee normal operating procedure 0-NOP-99.06, "Cold Weather Preparations" and administrative procedure OP-AA-102-1002, Attachment "Seasonal Readiness." The inspectors verified conditions were met for entering the subject procedure and that equipment status was verified as directed by the procedure. Action requests (ARs) in the licensee's corrective action program (CAP) 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 were exposed to the outside weather conditions to identify any potential adverse conditions. This inspection constitutes one readiness for seasonal extreme weather conditions 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 (IP 71111.04)

.1 Partial Equipment Walkdowns (IP 71111.04Q)

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 those issues were documented in the CAP. This inspection constitutes two samples as noted below. Documents reviewed are listed in the Attachment.

- Unit 1, 1B component cooling water (CCW) train while the 1A CCW heat exchanger (HX) was out of service (OOS) for planned cleaning
- Unit 2, 2B, and 2C intake cooling water (ICW) trains with the 2A ICW pump OOS for a planned motor replacement

b. Findings

No findings were identified.

.2 Complete System Walkdown (IP 71111.04S)

a. Inspection Scope

The inspectors conducted a detailed walkdown or review of the alignment and condition of the 2B EDG 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: (1) valves were correctly positioned and did not exhibit leakage that would impact their function; (2) electrical power was available as required; (3) major portions of the system and components were correctly labeled, cooled, and ventilated; (4) hangers and supports were correctly installed and functional; (5) essential support systems were operational; (6) ancillary equipment or debris did not interfere with system performance; (7) tagging clearances were appropriate; and (8) 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 (WRs)/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 (IP 71111.05)

Fire Area Walkdowns (IP 71111.05Q)

a. Inspection Scope

The inspectors toured the following plant areas during this inspection period to evaluate conditions related to control of transient combustibles and ignition sources, 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 procedures 1800022, "Fire Protection Plan," and ADM-19.02, "Pre-Fire Plan Standard Operating Procedure." 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 2, 2A high pressure safety injection (HPSI) and containment spray (CS) pump area
- Unit 2, 2A and 2B shutdown heat exchanger rooms
- Unit 1, cable spreading room and switchgear rooms
- Unit 1, ICW pump area
- Unit 1, CCW pump and HX area

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program and Licensed Operator Performance (IP 71111.11)

.1 Resident Inspector Quarterly Review (IP 71111.11Q)

a. Inspection Scope

On October 9, 2017, the inspectors observed and assessed licensed operator actions during the annual training requalification exam in the control room simulator. The simulated scenario involved a loss of CCW to the reactor coolant pumps (RCPs), a manual reactor trip and a steam generator tube rupture. Additionally, the scenario included an Emergency Alert classification for the loss of the reactor coolant system (RCS) barrier, and notification to the state and the NRC. Documents reviewed are listed in the Attachment.

The inspectors also reviewed simulator physical fidelity and specifically evaluated the following attributes related to the operating crews' performance:

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

This inspection constitutes one sample.

b. Findings

No findings were identified.

.2 Control Room Observations (IP 71111.11Q)

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 evolutions:

- October 11, 2017, Unit 2 downpower to approximately 81 percent RTP to support planned turbine valve testing
- October 28-29, 2017, Unit 2 startup activities and power ascension following a reactor startup

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 samples.

b. Findings

No findings were identified.

.3 Annual Review of Licensee Requalification Examination Results (IP 71111.11A)

a. Inspection Scope

On October 27, 2017, the facility licensee completed the annual requalification operating examinations required to be administered to all licensed operators in accordance with Title 10 of the *Code of Federal Regulations* (CFR) 55.59(a)(2), “Requalification Requirements,” of the NRC’s “Operator’s Licenses.” 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 Inspection Procedure (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. This inspection constitutes one sample.

b. Findings

No findings were identified.

.4 Licensed Operator Requalification (71111.11B)

a. Inspection Scope

The inspectors reviewed the facility operating history and associated documents in preparation for this inspection. During the week of October 16, 2017, 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 Inspection Procedure 71111.11, “Licensed Operator Requalification Program.” The inspectors also evaluated the licensee’s simulation facility for adequacy for use in operator licensing examinations using ANSI/ANS-3.5-2009, “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, simulator scenarios, licensee procedures, on-shift records, simulator modification request records, simulator performance test records, operator feedback records, licensed operator qualification records, remediation plans, watchstanding records, and medical records. The records were inspected using the criteria listed in Inspection Procedure 71111.11. Documents reviewed are listed in the Attachment. This inspection constitutes one sample.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (IP 71111.12Q)

a. Inspection Scope

The inspectors reviewed the performance data and associated AR for the equipment issue 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' efforts focused on maintenance rule 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. Documents reviewed are listed in the Attachment. This inspection constitutes one sample.

- AR 2227979, Unit 1 containment fan cooler HVS-1B tripped after start

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors completed in-office reviews, plant walkdowns, and control room inspections of the licensee's online and shutdown risk assessment of emergent or planned maintenance activities. 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 administrative 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 systems, structures, and components (SSCs) listed below. This inspection constitutes four samples. Documents reviewed are listed in the Attachment.

- Unit 1, Green OLRM assessment with 1A CCW HX OOS for planned maintenance and 1A EDG OOS for planned surveillance testing
- Unit 2, Green OLRM assessment with 2A HPSI and 2A low pressure safety injection (LPSI) OOS for a planned code runs

- Unit 2, Green OLRM assessment with 2C ICW, 2A CCW, and 2A EDG OOS for planned maintenance
- Unit 2, Yellow OLRM assessment with 2B CCW HX and CS OOS for planned maintenance

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (IP 71111.15)

a. Inspection Scope

The inspectors reviewed ARs' interim dispositions and operability determinations or functionality assessments 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 reviewed the applicable Updated Final Safety Analysis Report (UFSAR), and associated supporting documents and procedures, and interviewed plant personnel to assess the adequacy of the interim disposition. Documents reviewed are listed in the Attachment. This inspection constitutes four samples as noted below. The following ARs were reviewed:

- AR 2227793, Unit 2, 2C charging pump center plunger leakage
- AR 2230544, Unit 1, CCW pipe support spring can degraded
- AR 2234077, Unit 2, Control element assembly (CEA)-49 transferred to lower gripper
- AR 2239658, Unit 2 temperature control valve (TCV)-14-4A failed at the 67 percent position

b. Findings

No findings were identified.

1R17 Evaluation of Changes, Tests, and Experiments (IP 71111.17T)

(Closed) Unresolved Item (URI) 05000335/2017007-01, Question Regarding Adequacy of Evaluation of Hot Leg Injection Actions

a. Inspection Scope

An unresolved item (URI) was opened regarding the adequacy of a 10 CFR 50.59 evaluation performed for procedures related to post-accident hot leg injection (HLI) alignment. The URI was opened to provide for further review of the licensee's licensing basis regarding the HLI actions that are needed to mitigate boron precipitation following loss of coolant accidents to determine if a performance deficiency (PD) existed. Specifically, Engineering Change (EC) 284437, "Evaluation of Actions Required to Mitigate Hot Leg Injection Single Failure Vulnerability," Revision 0, was created to implement actions needed to mitigate a single failure vulnerability associated with HLI by installing temporary power jumpers to valves in the HLI flow path. The inspectors noted that the guidance in Nuclear Energy Institute (NEI) 96-07, "Guidelines for 10 CFR 50.59 Implementation," revision 1, section 4.3.2, "Does the Activity Result in More Than a

Minimal Increase in the Likelihood of Occurrence of a Malfunction of an SSC Important to Safety?," considers a reduction in system/equipment redundancy, diversity, separation, or independence, as a more than minimal increase and would require NRC review and approval prior to implementation. At the time of the inspection, documented in inspection report 2017007 (Agencywide Documents Access and Management System (ADAMS) Accession Number ML17202G4642), the inspectors were unable to locate all relevant licensing basis documents regarding HLI action requirements for redundancy, and electrical and physical separation, or prior NRC approvals of these actions. The inspectors also noted that the guidance in NEI 96-07, section 4.3.3 stated, "Activities affecting on-site dose consequences that may require prior NRC approval are those that impede required actions inside or outside the control room to mitigate the consequences of reactor accidents." At the time the URI was opened, it was unclear to inspectors how the on-site dose consequences due to actions outside of the control room had previously been evaluated.

The inspectors reviewed relevant docketed licensing basis documents regarding the NRC's acceptance of the St. Lucie Unit 1 boron precipitation mitigation actions. It was determined that the NRC's acceptance of the St. Lucie Unit 1 boron precipitation mitigation strategy occurred on March 1, 1976, in Supplement No. 2 to the Safety Evaluation of the St. Lucie Plant Unit No. 1, and in a letter dated March 29, 1982 (ADAMS Accession Number ML17212B492). The NRC's review guidelines for the HLI strategy was described in Reference 1 to the March 29, 1982, letter, and allowed certain local manual actions to be credited. The inspectors' review revealed that emergency procedure 0120042, "Loss of Reactor Coolant," Revision 19, was reviewed by the NRC during its review of the St. Lucie Unit 1 boron precipitation mitigation strategy. The procedure included direction to install the electrical jumpers in Appendix A, "Hot Leg Injection," step 3, although the procedure was not specific in its directions. The inspectors noted that neither the UFSAR, nor the 10 CFR 50.59 evaluation for EC 284437 contained discussion of these details regarding the NRC's review of the St. Lucie Unit 1 HLI actions. Because the St. Lucie boron precipitation mitigation strategy was previously reviewed and approved by the NRC, the inspectors determined that the issues with installation of the electrical jumpers with respect to redundancy, diversity, separation, or independence did not warrant a license amendment, and the conclusion reached in the 10 CFR 50.59 evaluation was adequate.

Subsequent to the issuance of URI 05000335/2017007-01, the licensee further reviewed the potential on-site dose to personnel performing the jumper installation actions outside of the control room, and documented this review in NAI-2016-001, "St. Lucie Unit 1 Post-LOCA Mission Dose- Hot Leg Injection Jumpers." The inspectors reviewed the results of this review. The review concluded that the dose resulting from the jumper installation actions would remain within the general design criteria (GDC) 19 limits as stated in NEI 96-07, section 4.3.3, and that it would also remain within the limits stated in the St. Lucie Unit 1 UFSAR section 12.1.6.4 for extended power uprate conditions.

The URI identified as 05000335/2017007-01 is now closed. Documents reviewed are listed in the Attachment.

b. <u>Findings</u>

No findings were identified. However, one minor violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings” was identified for the licensee’s failure to follow their procedure EN-AA-203-1202, “10 CFR 50.59 Evaluation.” Specifically, section 4.2.5, required, in part, “The Qualified Preparer shall complete Part II of EN-AA-203-1202-F01 and answer each of the eight questions Yes or No and provide a written basis that supports the response. NEI 96-07, Revision 1 should be used as guidance in answering the eight questions.” The licensee did not adequately use the NEI 96-07 guidance in answering the questions. Specifically, NEI 96-07, revision 1, section 4.3.3, “Does the Activity Result in More Than a Minimal Increase in the Consequences of an Accident?” stated “[f]or changes affecting the dose to operators performing required actions outside the control room, an increase is considered more than minimal if the resultant ‘mission dose’ exceeds applicable GDC 19 criteria.” The licensee’s response to this question did not consider the mission dose to the operators performing the jumper installation outside of the control room. When the licensee evaluated the mission dose, they determined the dose would remain within the GDC 19 criteria and the limits in the Unit 1 UFSAR, therefore no license amendment request was necessary. The inspectors determined that the licensee’s failure to follow procedure EN-AA-203-1202 did not result in the licensee incorrectly determining that the activity did not require prior NRC review and approval in accordance with 10 CFR 50.59. The licensee entered this issue into their corrective action program as AR 2216120. This failure to comply with 10 CFR 50, Appendix B, Criterion V, constitutes a minor violation that is not subject to enforcement action in accordance with the NRC’s Enforcement Policy.

1R19 <u>Post Maintenance Testing (IP 71111.19)</u>

a. <u>Inspection Scope</u>

For maintenance WOs, 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 as noted below. The WOs are listed below:

- WO 40537066, Unit 1 auxiliary feedwater actuation system (AFAS) cabinet B power switch (P/S 304) replacement
- WO 40323105, Unit 2, 2A ICW pump motor replacement
- WO 40474109, Unit 1, 1B ICW pump motor preventative maintenance
- WO 40503662, Unit 2, replacement of CEA-49 subgroup 13 power switch
- WO 40421955, Unit 2, 2C ICW pump motor and pedestal replacement

b. <u>Findings</u>

No findings were identified.

1R22 Surveillance Testing (IP 71111.22)

a. Inspection Scope

The inspectors either reviewed or witnessed surveillance tests to verify that the tests met TS, the UFSAR, the licensee's procedural requirements, and demonstrated the systems were capable of performing their intended safety functions and their operational readiness. In addition, the inspectors evaluated the effect of the testing activities on the plant to ensure that conditions were adequately addressed by the licensee staff and that 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. This inspection constitutes three samples as noted below. The following surveillances were reviewed:

In-Service Tests:
- 2-OSP-99.08A, A Train Quarterly Non Check Valve Cycle Test

Routine Surveillance Tests:
- 2-OSP-63.01, RPS Logic Matrix Test
- 2-OSP-69.01, Nuclear and Delta T Power Calibration (30 percent RTP)

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (IP 71151)

.1 Mitigating Systems Cornerstone

a. Inspection Scope

The inspectors checked licensee submittals for the Unit 1 and Unit 2 mitigating system performance indicators (MSPIs) listed below for the period October 1, 2016 through September 30, 2017, to verify the accuracy of the performance indicator (PI) data reported during that period. Performance indicator definitions and guidance contained in Nuclear Energy Institute (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, condition reports, 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 performance indicator data collection, evaluation, and distribution. The PIs reviewed are listed below:

- Unit 1 and Unit 2 emergency alternating current (AC) power systems
- Unit 1 and Unit 2 residual heat removal systems
- Unit 1 and Unit 2 heat removal systems
- Unit 1 and Unit 2 high pressure injection systems
- Unit 1 and Unit 2 cooling water systems

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (IP 71152)

.1 Daily Review

a. Inspection Scope

As required by Inspection Procedure 71152, “Problem Identification and Resolution,” and to help identify repetitive equipment failures or specific human performance issues for followup, the inspectors performed a screening of items entered daily into the licensee’s CAP. This review was accomplished by reviewing daily printed summaries of action requests and by reviewing the licensee’s electronic AR database. Additionally, reactor coolant system unidentified leakage was checked on a daily basis to verify no substantive or unexplained changes.

b. Findings

No findings were identified.

.2 Semi-Annual Trend Review:

a. Inspection Scope

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 focused on repetitive equipment issues, but also considered the plant status reviews, plant tours, licensee trending efforts, and the results of daily inspector CAP item screenings discussed in Section 4OA2.1. The inspectors’ review nominally considered the six month period of July 2017 through December 2017, although some examples expanded beyond those dates when the scope of the issue warranted. The inspectors verified that the ARs were dispositioned in accordance with the CAP as specified in licensee procedure PI-AA-104-1000, “Condition Reporting.” Documents reviewed included department self-assessment and trend reports as well as engineering system health reports. Documents reviewed are listed in the Attachment. This inspection constitutes one sample.

b. Findings and Observations

No findings were identified. The inspectors identified one adverse trend associated with Unit 2 rod control system. Since June 2016, the inspectors noted six instances when Unit 2 CEAs automatically transferred from the upper gripper to the lower gripper due to power switch problems. Three of the six transfers involved CEA-60. The inspectors’ observations were discussed with the licensee who also noted the same adverse trend for both units’ rod control systems. The licensee had actions to replace the Unit 1 and Unit 2 rod control systems as part of a long term asset management program. However, the earliest date scheduled for implementation of the replacement system was years away. The licensee documented the adverse trend in their CAP as AR 2241912.

The AR will track near term actions necessary to improve the health of the rod control system before the system is replaced.

.3 Annual Sample: Gas Accumulation Exceeded Operability Limits in the 1A Containment Spray (CS) Header

a. Inspection Scope

The inspectors performed an in-depth review of Florida Power and Light's (FPL's) evaluations and corrective actions associated with AR 2224958 and 2225004. ARs 2224958 and 2225004 were originated on September 14, 2017, and documented gas that accumulated in the 1A CS pump discharge piping to containment isolation valve, flow control valve (FCV-07-1A), at pipe location CA7. The gas void was in excess of operability limits established by 1-OSP-03.31A, "UT Evaluation of A Train ECCS Monitored Locations," and was identified on September 14, 2017. CS system flow path piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation was necessary for proper operation of the CS trains and other emergency core cooling systems. At piping location CA7 gas monitoring was periodically performed using ultrasonic testing to prevent a water hammer event. Gas accumulation monitoring of the CS system at locations susceptible to gas accumulation was required by TS surveillance requirement 4.6.2.1.c.

The inspectors assessed FPL's problem identification threshold, technical analyses, extent of condition reviews, and the prioritization and timeliness of corrective actions to determine whether FPL was appropriately identifying, characterizing, and correcting problems associated with this issue. The inspectors compared the actions taken to the requirements of FPL's corrective action program and 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action. In addition, the inspectors reviewed documentation associated with this issue and interviewed engineering personnel to assess the effectiveness of the implemented corrective actions and the actions planned to complete full resolution of the issue.

b. Findings and Observations

A licensee-identified Green non-cited violation (NCV) was identified. Enforcement aspects of this NCV are discussed in Section 4OA7.

FPL previously noted that at gas accumulation monitoring point CA7, voids were identified but were within the operability limit of 1-OSP-03.31A. AR 2178644 documented a void arc length of 5.75 inches on January 9, 2017, and AR 2196817 documented a void arc length of 7.75 inches on April 6, 2017. On April 27, 2017, FPL completed a condition evaluation associated with AR 2196817 and concluded that the most likely source of the gas void at location CA7 was gas that had come out of solution. Corrective actions included additional gas monitoring at CA7 and CA7 was verified full on May 18, 2017.

On September 14, 2017, ARs 2224958 and 2225004 documented a 16 inch void arc length at CA7. When the arc length in excess of operability limits was identified at 1415 hours, control room operators promptly declared the 1A CS train inoperable. TS 3.6.2.1.1.a, required the 1A CS train be restored to an operable status within 72 hours, otherwise Unit 1 was required to be shutdown to Mode 3 within the next 6 hours. On September 14, 2017, plant operators promptly filled and vented the 1A CS pump header and declared the 1A CS train operable at 1505 hours.

On October 6, 2017, FPL completed an issue investigation and determined that quarterly inservice testing of FCV-07-1A to stroke open and then return to a closed position had partially emptied the 1A CS header to the normally void spray header downstream of FCV-07-1A. Inservice testing of FCV-07-1A occurred on September 13, 2017, which was 17.5 hours prior to the gas accumulation monitoring that identified the void at CA7. Inservice testing was performed in accordance with 1-OSP-99.08A, “A Train Quarterly Non Check Valve Cycle Test.”

The inspectors noted that anytime FCV-07-1A was cycled open, the 1A CS header may partially drain. FPL established a gas accumulation monitoring program in response to NRC Generic Letter (GL) 2008-01, “Managing Gas Accumulation in ECCS, Decay Heat Removal, and CS Systems.” The enclosure to GL 2008-01, “Technical Considerations for Reasonably Assuring Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems Operability,” identified system realignments as a source of gas accumulation in systems. 1-OSP-99.08A required FCV-07-1A to be opened to the 1A CS header, a system realignment, potentially voiding the 1A CS header, and did not include instructions to fill and vent the 1A CS pump header after FCV-07-1A was closed in its normal standby alignment. Although the refuel water tank was normally aligned to provide a source of water to the suction of the CS pumps, the gravity fill may be insufficient to prevent voiding at CA7 when FCV-07-1A was opened. The inspectors noted that FPL should have identified the inservice testing requirements to stroke open the CS header discharge valves FCV-07-1A and FCV-07-1B and then closed to its normal position was a system realignment that could potentially drain the Unit 1 CS headers. Condition evaluation 2196817 completed on April 27, 2017, was also an opportunity to identify the valve strokes as a potential to develop voids in the CS pump discharge lines. FPL entered these issues and observations into their CAP as AR 2238532.

4OA3 Followup of Events and Notices of Enforcement Discretion (IP 71153)

.1 Unit 2 Automatic Reactor Trip due to a Turbine Trip

a. Inspection Scope

On October 26, 2017 at 0212 hours, St. Lucie Unit 2 experienced a reactor trip due to a loss of load from a turbine trip. Following the reactor trip, the AFAS-1 actuated due to a low 2A steam generator (SG) water level. The AFAS-1 actuation isolated main feedwater to the 2A SG and lined up AFW to the 2A SG. The 2A SG water level was restored by the AFW system. In addition, one of the two MFIVs for the 2A steam generator did not close as expected by the actuation. The inspectors reviewed operator logs, computer and recorder data, and the post trip report to verify plant equipment, other than noted above, responded appropriately. The inspectors provided details regarding operator and equipment performance to NRC management. The licensee determined that degraded electronic components in the turbine DEH control system initiated the turbine trip. Additionally, the MFIV was found to have a faulty closing solenoid. Both the DEH system and MFIV solenoid issues were addressed prior to unit startup. The licensee determined that the 2A SG low power feedwater valve, LCV-9005 was a different model than the one used for the 2B SG. The low 2A SG water level was due to LCV-9005 being setup incorrectly for the model of the valve to allow enough feedwater flow to automatically recover the 2A SG water level after a unit trip. Compensatory guidance was provided to operations to manually adjust the position of LCV-9005 as necessary to maintain 2A SG water level in the event of a unit trip. After the unit was returned to 100 percent RTP, a new magnetic array at LCV-9005 was installed to allow the valve to go to the required position post-trip in order to recover SG water. The inspectors verified the cause of the trip, the AFAS-1 actuation, and the failure of a MFIV to close were appropriately resolved prior to unit restart. The unit was restarted on October 28, 2017 and was returned to 100 percent RTP on October 29, 2017. The licensee will provide the NRC a written licensee event report (LER) associated with this event as required by 10 CFR 50.73. Any regulatory significance associated with the event will be determined during the NRC's closeout review of the LER.

b. Findings

No findings were identified.

.2 (Closed) LER 05000335/2017-003-00, Inadequate Reactor Protection System Trip Process for Inoperable Channel Results in Operation in a Condition Prohibited by Technical Specifications

a. Inspection Scope

On September 12, 2017, at 1308 hours, St. Lucie Unit 1 was in Mode 2, performing a reactor startup. At 1522 hours, the operators noted that the "B" channel reactor protection system (RPS) high startup rate (HSUR) bistable had not automatically tripped as expected for the existing plant conditions of approximately 3 percent RTP. The operators placed the "B" channel of RPS HSUR in a tripped condition in accordance with procedure 1-AOP-99.01, "Loss of Tech Spec Instrumentation," by pulling the bistable trip unit (BTU) and entered TS 3.3.1.1, Table 3.3-1, Functional Unit 11, Action 2, which required the channel to be bypassed or tripped within one hour. The reactor startup continued with the channel in trip as allowed by TS Limiting Condition for Operation (LCO) 3.3.1.1. The licensee determined that during the September 2017 startup, the bistable did not trip at $1x10^{-4}$ percent RTP, because the method used set the bistable trip in the presence of an active nuclear instrument (NI) signal. The licensee determined that the "B" wide range NI detector failed completely and indicated zero output on February 10, 2017, after the setpoint had been reduced. This changed the input signal to the HSUR bistable from the rate circuit, preventing bistable trip conditions from being satisfied. The inspectors reviewed the LER and the associated organizational effectiveness investigation checklist (AR 2224729) to verify the accuracy and completeness of the LER and the appropriateness of the licensee's corrective actions. The inspectors also reviewed the LER to identify any PDs associated with the event.

b. Findings

Introduction: A Green, self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," was identified for the licensee's failure to have an adequate procedure for reducing the trip setpoint of the "B" channel of the reactor protection system (RPS) high startup rate (HSUR) bistable.

Description: On February 10, 2017, the “B” RPS HSUR channel was declared inoperable due to problems with the “B” wide range nuclear instrument detector. The associated trip bistable was placed in a reduced setpoint tripped condition, as one of the conditional options required by TSs and 1-AOP-99.01, “Loss of Tech Spec Instrumentation,” utilizing guidance located in work order (WO) 40495848. Once placed in this condition, the “B” RPS HSUR channel bistable trip would automatically generate a trip signal between $1x10^{-4}$ to 15 percent RTP. Below and above these power levels, the trip function would be automatically bypassed. On September 12, 2017, at 1308 hours, St. Lucie Unit 1 was in Mode 2, performing a reactor startup. At 1522 hours, the operators noted that the “B” channel RPS HSUR bistable had not automatically tripped as expected for the existing plant conditions of approximately 3 percent RTP. The bistable should have indicated a tripped condition at approximately 1410 hours when power initially reached $1x10^{-4}$ percent RTP. The operators placed the “B” channel of RPS HSUR in a tripped condition in accordance with procedure 1-AOP-99.01, by pulling the BTU and entered TS 3.3.1.1, Table 3.3-1, Functional Unit 11, Action 2, which required the channel to be bypassed or tripped within one hour. The reactor startup continued with the channel in trip as allowed by TS LCO 3.3.1.1.

TS LCO 3.3.1.1, stated in part, that for Mode 1 and Mode 2, with the number of operable channels less than the total number of channels, startup and/or power operation may proceed provided the inoperable channel be placed in a bypassed or tripped condition within one hour. Licensee abnormal operating procedure 1-AOP-99.01, provided two options for placing the bistable in a tripped condition, (1) physically pulling the BTU or (2) reducing the bistable trip setpoint. Pulling the BTU would cause the channel to generate a HSUR trip signal that would not be automatically bypassed above 15 percent RTP. Adjusting the bistable trip setpoint, allowed the trip signal to be active between $1x10^{-4}$ and 15 percent RTP and automatically bypassed above 15 percent RTP.

Reducing the bistable trip setpoint utilizing procedure 1-AOP-99.01 adjusted the HSUR bistable so that a trip signal would be generated at $1x10^{-4}$ percent RTP based on the associated NI detector output. The licensee determined that during the September 2017 startup, the bistable did not trip at $1x10^{-4}$ percent RTP, because the method used set the bistable trip in the presence of an active NI signal. The licensee determined that the “B” wide range NI detector failed completely and indicated zero output on February 10, 2017, after the setpoint had been reduced. This changed the input signal to the HSUR bistable from the rate circuit, preventing bistable trip conditions from being satisfied. Procedure 1-AOP-99.01 was specific in how to meet the requirements of TS LCO 3.3.1.1, but the process the licensee had in place to complete this requirement was not adequate in that it did not evaluate all potential failure conditions when setting the HSUR bistable trip point. This resulted in the “B” channel wide range nuclear instrument HSUR bistable not being in a tripped condition as required by TS from February 10, 2017, until September 12, 2017, when the BTU was pulled.

The inspectors determined that the first opportunity the licensee had to discover the “B” HSUR bistable was not in a tripped condition, as required by TS, was during the unit startup on September 12, 2017, when power reached $1x10^{-4}$ percent RTP.

Analysis: The licensee failed to establish an adequate procedure to place the “B” channel wide range nuclear instrument in a tripped condition. Specifically, the failure to have an adequate procedure as required by 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was a PD. This deficiency resulted in a violation of TS LCO 3.3.1.1. The inspectors determined that the finding was more than minor because it was associated with the Mitigating Systems cornerstone attribute of procedural quality and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, there was no procedure to perform the setpoint reduction method as identified in 1-AOP-99.01, the only direction was to “Contact I&C” in the step. The Instrumentation and Control (I&C) processes used to implement the HSUR reduced setpoint reduction method were inadequate, in that they did not evaluate all potential failure conditions when setting the HSUR bistable.

Using Inspection Manual Chapter (IMC) 0609, Attachment 4, “Initial Characterization of Findings,” Table 2, the finding was determined to affect the Mitigating Systems cornerstone due to a functional degradation of the RPS. IMC 0609, Appendix A, “The Significance Determination Process (SDP) for Findings At-Power,” Exhibit 2 “Mitigating Systems Screening Questions,” was used to further evaluate this finding. The finding screened as Green because while the degradation affected a single RPS trip signal, it did not affect the function of other redundant trips; and the finding did not involve control manipulations that unintentionally added positive reactivity; and finally the finding did not result in a mismanagement of reactivity by operators.

Using IMC 0310, “Aspects Within the Cross-Cutting Areas,” the inspectors determined that the finding had a cross-cutting aspect in the area of human performance. Specifically, the cross-cutting aspect of “Resources” was assigned to the finding because the licensee did not ensure an adequate procedure was available to implement the HSUR setpoint reduction. (H.1)

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” required, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances. Contrary to these requirements, the licensee failed to establish an adequate procedure to place the “B” channel wide range nuclear instrument in a tripped condition. The I&C processes used to implement the HSUR reduced setpoint reduction method were inadequate, in that, they did not evaluate all potential failure conditions when setting the HSUR bistable. This resulted in Unit 1 not meeting LCO 3.3.1.1, Action 2.a, from February 10, 2017 to September 12, 2017, while Unit 1 was in Mode 1 or 2. The licensee included this issue in their CAP as AR 2224729. Following discovery of the condition, the licensee initiated immediate corrective actions to place “B” channel RPS HSUR in trip, meeting the TS requirement. Because this violation was of very low safety significance and it was entered into the licensee’s CAP, this violation is being treated as an NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy.
(NCV 05000335/2017004-01, Inadequate Reactor System Trip Process for Inoperable Channel Results in Operation in a Condition Prohibited by Technical Specifications).

.3 <u>(Closed) LER 05000389/2017-003-00, Improper System Realignment Resulted in Loss of Steam Driven Auxiliary Feedwater Pump Flow Indication</u>

a. <u>Inspection Scope</u>

On October 25, 2017, with St. Lucie Unit 2 operating at approximately 100 percent RTP, the licensee discovered that both TS required flow transmitters for the 2C AFW pump had been isolated since October 17, 2017. The licensee's investigation determined that the maintenance personnel that completed the monthly channel check on October 17, 2017, failed to follow surveillance maintenance procedure 2-SMI-09.05C, "2C Auxiliary Feedwater Pump Flow Channel Check," resulting in the isolation of both 2C AFW pump flow transmitters and in a condition prohibited by TSs.

The inspectors reviewed the LER and the associated organizational effectiveness investigation checklist (AR 2232779) to verify the accuracy and completeness of the LER and the appropriateness of the licensee's corrective actions. The inspectors also reviewed the LER to identify any licensee PDs associated with the event.

b. <u>Findings</u>

<u>Introduction</u>: A Green, self-revealing, NCV of TS 6.8.1 was identified for the licensee's failure to adequately implement a maintenance procedure during a monthly flow channel check for the 2C AFW pump. Specifically, the licensee failed to implement as-written surveillance maintenance procedure 2-SMI-09.05C, "2C Auxiliary Feedwater Pump Flow Channel Check," when performing the channel checks for both 2C AFW pump flow transmitters.

<u>Description</u>: On October 25, 2017, with Unit 2 operating at 100 percent RTP, maintenance personnel were troubleshooting the cause of flow "spikes" on flow transmitter FT-09-2C1 for the 2C AFW pump. With 2C AFW pump not in operation, FT-09-2C1 should have indicated approximately 0 gallons per minute. Troubleshooting revealed that the isolation valves to the transmitter were closed. At 1910 hours the flow transmitter was declared inoperable. At 1915 hours, the flow transmitter was placed back in service. The second 2C AFW pump flow transmitter, FT-09-2C2, was also found isolated and subsequently placed back in service at 1925 hours.

The licensee's investigation determined that the individuals involved with completing the monthly flow channel check of the flow transmitters on October 17, 2017 failed to properly perform the restoration lineups in accordance with surveillance maintenance procedure 2-SMI-09.05C. An extent of condition review determined that the remaining Unit 2 and Unit 1 AFW pump flow transmitters were properly in service.

TS 3.3.3.6, "Accident Monitoring Instrumentation," Table 3.3.10, required a minimum of one AFW flow instrument per pump. With both instruments isolated, TS 3.3.3.6, Action "b" states, in part, that with the number of operable accident monitoring channels less than the minimum channels operable requirements of Table 3.3.10, either restore the channel to operable status within 48 hours or be in hot standby in 6 hours and hot shutdown in 12 hours. Both flow transmitters for the 2C AFW pump were isolated and inoperable for approximately 190 hours. The licensee failed to meet these TS actions and found the condition to be reportable to the NRC under 10 CFR 50.73(a)(2)(i)(B) as an operation or condition that was prohibited by the TSs.

Corrective actions completed for this event included suspending the qualifications of the maintenance personnel involved, remediation of the personnel involved, completing an extent of condition review, and briefing maintenance and site personnel of this event. The licensee entered this issue into their corrective action program as AR 2232779.

Analysis: The licensee's failure to follow surveillance maintenance procedure 2-SMI-09.05C, was a PD. The PD was more than minor because it was associated with the Human Performance attribute of the Mitigating Systems cornerstone and it adversely affected the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The PD adversely affected the licensee's ability to monitor 2C AFW flow during a design basis accident. The inspectors evaluated the risk of this finding using IMC 0609, "Significance Determination Process," Attachment 4, "Initial Characterization of Findings," and IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power." Using Exhibit 2, "Mitigating Systems Screening Questions," of IMC 0609, Appendix A, the inspectors determined that the finding was of very low safety significance (Green) because it did not represent a deficiency affecting the design or qualification of a mitigating system; it did not represent a loss of system and/or function; it did not represent an actual loss of function for at least a single train for more than its TS allowed outage time; and it did not represent an actual loss of function of one or more non-TS trains of equipment designated as high safety-significant in accordance with the licensee's maintenance rule program.

The finding involved the cross-cutting area of human performance, with an aspect of avoiding complacency (H.12), in that, the licensee failed to ensure that personnel effectively used human performance tools during the AFW pump flow channel check to ensure procedure steps were completed as required.

Enforcement: Unit 2 TS 6.8.1, "Procedures and Programs," required, in part, that written procedures be implemented covering activities referenced in Regulatory Guide 1.33, Revision 2, dated February 1978, including procedures for performing surveillance and calibration activities. Licensee surveillance maintenance procedure 2-SMI-09.05C, "2C Auxiliary Feedwater Pump Flow Channel Check," Revision 4, Steps 4.1.13 and 4.2.13, provided instructions to return the transmitters to service for FT-09-2C1 and FT-09-2C2 respectively. Contrary to the above, the maintenance personnel failed to properly return both flow transmitters to service for the 2C AFW pump. The condition existed from October 17, 2017 until being corrected on October 25, 2017. Upon discovery the flow transmitters were declared inoperable and subsequently, the condition was promptly restored to normal. Because the licensee entered the issue into their corrective action program as AR 2232779 and the finding is of very low safety significance (Green), this violation is being treated as an NCV, consistent with Section 2.3.2.a of the Enforcement Policy. (NCV 05000389/2017004-02, Failure to Follow Surveillance Maintenance Procedure Resulting in a Condition Prohibited by Technical Specifications).

.4 <u>(Closed) LER 05000335/2017-002-00, Inadequate Hot Leg Injection Procedure Results in Unanalyzed Condition</u>

a. <u>Inspection Scope</u>

The subject LER was submitted on September 28, 2017, for an event that occurred on July 31, 2017. The LER documented that procedural manual actions needed to mitigate postulated electrical single failures in the St. Lucie Unit 1 hot leg injection (HLI) flow path were inadequate. The inspectors reviewed the LER and associated Apparent Cause Evaluation (ACE) to verify the accuracy and completeness of the LER and the appropriateness of the licensee's corrective actions. The inspectors also reviewed the LER to identify any licensee PDs associated with the event. .

b. <u>Findings</u>

<u>Introduction</u>: The NRC-identified a Green non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, for the licensee's failure to identify that their procedures lacked actions to install control power jumpers that are required to defeat the reactor coolant systems (RCS) pressure interlocks for the shutdown cooling (SDC) suction line motor operated valves (MOVs), when aligning the plant for hot leg injection (HLI) and then correct the condition.

<u>Description</u>: The need to address the potential for boron precipitation to ensure successful long term core cooling following a large break loss of coolant accident (LOCA) was identified as an industry issue during the initial licensing of St. Lucie Unit 1. Because the original design for St. Lucie Unit 1 did not provide dedicated hot leg injection paths, St. Lucie Unit 1 was licensed to develop procedures that utilized the existing low pressure safety injection (LPSI) and/or high pressure safety injection (HPSI) flow paths to provide for simultaneous hot and cold leg injection, which would prevent significant boron precipitation.

There were five potential paths for establishing simultaneous hot and cold leg injection. The preferred HLI flow path was to direct the discharge of one LPSI pump through the 2-inch SDC warm-up line to the opposite LPSI pump's suction line, and "backwards" through the suction line into the hot leg. The cold leg injection was via the normal HPSI pump operation. The LPSI suction line flow path requires the opening of two MOVs in series to be successful; each valve was powered from a different electric bus. The primary HLI injection flow path used normally closed, fail-as-is MOVs that were powered from train A and train B VAC buses. The alternate flow path used solenoid operated valves that were powered by 125 VDC battery bus A and B. Both trains of DC power were required for successful alignment of the alternate flow path. Successful alignment of the preferred and alternate flow paths required both trains of electric power to be available. Several electrical single failures would require jumper installation to manually recover the ability to align the primary flow path.

In 1999, the licensee wrote condition report (CR) 99-1278 and determined that a HLI flow path could be restored by using temporary jumpers to power the MOVs affected by the loss of an electrical train. However, HLI procedures were not revised and electrical jumpers were not fabricated. In 2008, CR 2008-35069 documented that the previously identified jumpers and procedure changes had not been implemented. CR 2008-35069 developed new tracking actions for the required procedure changes and jumper fabrication. Subsequently, in 2011 the licensee identified that the procedure changes and jumper fabrication identified in the 1999 and 2008 condition reports had not been implemented. Following the identification of this procedural vulnerability in 2011, the licensee fabricated power jumpers and implemented procedure 1-GME-100.03, "Installation and Removal of Temporary Power Jumpers for MOV V3481, V3652, V3432 AND V3444," to provide direction to install the power jumpers. In 2017, as followup to the issuance of URI 05000335/2017007-01, the licensee performed an in-depth review of all procedural actions associated with the use of jumpers on the HLI flow path and identified that, although the procedures provided for power jumper installation, the procedures lacked actions to install control power jumpers required to defeat the RCS pressure interlocks for the SDC suction MOVs when aligning the plant for HLI. Immediately following the identification of the procedural vulnerability, the licensee revised the associated procedures to ensure that appropriate guidance was in place for bypassing the de-energized interlocks for the associated shutdown cooling valves. In addition, the licensee performed a more detailed failure modes and effects analysis to ensure that the revised measures accounted for all possible single failures.

<u>Analysis</u>: The licensee's failure to identify and correct a condition adverse to quality was a PD. Specifically, the licensee failed to identify that their procedures lacked actions to install control power jumpers required to defeat the RCS pressure interlocks for the SDC suction MOVs when aligning the plant for HLI and then correct the condition. The inspectors determined that this finding was more than minor because it affected the Mitigating System cornerstone objective of ensuring the capability of the LPSI system to perform its required long term cooling safety function (HLI). The inspectors used IMC 0609, Att. 4, "Initial Characterization of Findings," for Mitigating Systems, and IMC 0609, App. A, "The Significance Determination Process (SDP) for Findings At-Power," and determined that a detailed risk evaluation was required due to the loss of system safety function. A regional Senior Reactor Analyst (SRA) performed the detailed risk evaluation using Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) Version 8.1.6 and a modified Version 8.50 of the Unit 1 Standardized Plant Analysis Risk (SPAR) model. The SRA modified the fault trees for the hot leg injection path to include jumper installation and developed a change set to model the failure. The result was a change in core damage frequency (CDF) of less that 1E-6/year, which is characterized as a finding of very low safety significance (Green). The dominant sequences involved a medium or large loss of coolant accident (LOCA) where sump recirculation failed due to unavailability of hot leg injection. The risk was mitigated by low likelihood of a LOCA and the electrical failures requiring jumpers to be installed. This issue and corrective actions were documented in the licensee's corrective action program as AR 2217631. This finding was not assigned a cross-cutting aspect because the underlying cause was a legacy issue and not indicative of current performance.

Enforcement: Title 10 of CFR Part 50, Appendix B, Criterion XVI, Corrective Action, required, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies and deviations are promptly identified and corrected. Contrary to the above, from November of 2011 to July of 2017, the licensee failed to identify and correct a condition adverse to quality. Specifically, the licensee failed to identify and correct the lack of procedural actions to install control power jumpers required to defeat the RCS pressure interlocks to ensure successful HLI alignment. The violation was entered into the licensee's corrective action program as AR 2217631. This violation is being treated as an NCV consistent with section 2.3.2.a of the Enforcement Policy. (NCV 05000335/2017004-03, Failure to Identify and Correct a Condition Adverse to Quality).

4OA5 Other Activities

.1 Contingency Plans for Licensee Strikes and Lockouts (IP 92709)

a. Inspection Scope

The union contract covering operations, maintenance and radiological protection personnel expired at midnight on October 31, 2017. As required by IP 92709, this inspection was implemented a few weeks prior to the contract expiration date to allow sufficient time to resolve any discrepancies identified in the licensee's contingency plan. The inspectors reviewed licensee "2017 Work Stoppage Contingency Plan," Revision 3. The new union contract was approved prior to October 31, 2017. No contingency plans were implemented. This inspection constitutes one sample.

b. Findings

No findings were identified

.2 Independent Spent Fuel Storage Installation (ISFSI) Inspections (IP 60855.1)

a. Inspection Scope

The inspectors reviewed reported changes made to the licensee's procedures and programs for the ISFSI to verify the changes made were consistent with the license and Certificate of Compliance (CoC) and did not reduce the effectiveness of the program. The inspectors, through direct observation and independent evaluation, observed the loading of dry shielded cask (DSC)-083 from the Unit 1 spent fuel pool. The inspectors verified the cask loading activities were performed in a safe manner and in compliance with approved procedures. Based on direct observation and review of selected records, the inspectors verified the licensee had properly identified each fuel assembly placed in DSC-083 that was subsequently placed in the ISFSI. The inspectors also observed activities associated with the transport and storage of casks, loading of spent fuel in casks, vacuum drying and seal welding activities, and the heavy lifts to remove the casks from the spent fuel pool and placing them in the cask handling facility. Documents reviewed are listed in the Attachment. This inspection constitutes one sample.

b. Findings

No findings were identified

4OA6 Meetings

Exit Meeting Summary

On October 20, 2017, the senior operations engineers discussed the results of the biennial licensed operator requalification inspection with Mr. T. Summers and other members of your staff. The inspectors noted that no proprietary information was reviewed during the inspection.

The resident inspectors and the senior reactor inspector presented the inspection results to Mr. DeBoer and other members of licensee management on January 11, 2018. 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 licensee-identified violation of NRC requirements was determined to be of very low safety significance (Green) and met the NRC Enforcement Policy criteria for being dispositioned as a Non-cited Violation.

10 CFR 50 Appendix B, Criterion V, Instructions, Procedures, and Drawings, requires in part that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, on September 13, 2017, FPL performed inservice testing of valve FCV-07-1A using 1-OSP-99.08A, A Train Quarterly Non Check Valve Cycle Test. The procedure instructions partially drained the 1A CS header and introduced a void greater in size than the operability limits established by 1-OSP-03.31A, “UT Evaluation of A Train ECCS Monitored Locations,” in the 1A CS pump discharge header. FPL identified the void during gas accumulation monitoring on September 14, 2017. This violation was associated with the Barrier Integrity 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 involve an actual reduction in function of hydrogen igniters in the reactor containment. The licensee entered this violation into its CAP as ARs 2224958 and 2225004. Corrective actions were initiated to require a fill and vent operation at pipe location CA7 after inservice testing of FCV-07-1A. The intended corrective actions were also extended to Unit 2 and the redundant train of Unit 1 CS system.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel:
T. Summers, Southern Region Vice President
D. DeBoer, Site Director
R. Baird, Training Manager
G. Bowen, Emergency Preparedness Manager
A. Dong, Maintenance Director
S. Duston, Chemistry Manager
J. Francis, Health Physics Manager
K. Frehafer, Licensing Engineer
M. Haskin, Projects Site Manager
B. Hinze, Senior Operations Instructor
M. Jones, Engineering Director
T. Miller, Assistant Operations Manager - Line
W. Parks, Operations Director
R. Sciscente, Licensing Engineer
C. Sizemore, Corporate Training Director
M. Snyder, Licensing Manager
T. Spillman, Assistant Operations Manager – Training
R. Stottlemire, Nuclear Assurance Supervisor
K. Alumbaugh, Gas Accumulation Monitoring Program Engineer
S. Riley, Senior Reactor Operator
R. Virgin, Operations Training Supervisor

NRC Personnel:
LaDonna B. Suggs, Chief, Branch 3, Division of Reactor Projects
P. Buckberg, Project Manager

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000335/2017004-01	NCV	Inadequate Reactor System Trip Process for Inoperable Channel Results in Operation in a Condition Prohibited by Technical Specifications (Section 4OA3.2)
05000389/2017004-02	NCV	Failure to Follow Surveillance Maintenance Procedure Resulting in a Condition Prohibited by Technical Specifications (Section 4OA3.3)
05000335/2017004-03	NCV	Failure to Identify and Correct a Condition Adverse to Quality (Section 4OA3.4)

Closed

05000335/2017007-01	URI	Question Regarding Adequacy of Evaluation of Hot Leg Injection Actions (Section 1R17)
05000335/2017-003-00	LER	Inadequate Reactor Protection System Trip Process for Inoperable Channel Results in Operation in a Condition Prohibited by Technical Specifications (Section 4OA3.2)
05000389/2017-003-00	LER	Improper System Realignment Resulted in Loss of Steam Driven Auxiliary Feedwater Pump Flow Indication (Section 4OA3.3)
05000335/2017-002-00	LER	Inadequate Hot Leg Injection Procedure Results in Unanalyzed Condition (Section 4OA3.4)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment
2-NOP-21.12, Intake Cooling Water Initial Alignment
1-NOP-14.01, Component Cooling Water System Initial Alignment
1-NOP-14.02B, Component Cooling Water System Operations
2-NOP-21.03A, 2A Intake Cooling Water Operation
2-NOP-21.03B, 2B Intake Cooling Water Operation
2-NOP-21.03C, 2C Intake Cooling Water Operation
2-NOP-21.12, Intake Cooling Water Initial Valve Alignment
2-NOP-59.03B, 2B Emergency Diesel Generator Standby Alignment
2-NOP-59.02B, 2B Emergency Diesel Generator Operations

Section 1R05: Fire Protection
ADM-0005729, Fire Protection Training, Qualification and Requalification

Section 1R11: Licensed Operator Requalification Program and Licensed Operator Performance
2-EOP-01, Standard Post Trip Actions
2-EOP-04, Steam Generator Tube Rupture
2-AOP-99.01, Loss of Technical Specification Instrumentation
2-GOP-123, Turbine Shutdown – Full Load to Zero Load
2-GOP-101, Reactor Operating Guidelines During Steady State and Scheduled Load Changes
2-GOP-201, Reactor Plant Startup – Mode 2 to Mode 1

Records:
License Reactivation Packages (6)
LORP Training Attendance records (10 records for Shift 3)
Medical Files (7)
Remedial Training Records (1)
Remedial Training Examinations (1)

Written Examinations:
Exam 820016F 2016 Annual RCO Exam A1, 11/11/16
Exam 820016F 2016 Annual SRO Exam A1, 11/11/16
Exam 820016F 2016 Annual RCO Exam A3, 11/25/16
Exam 820016F 2016 Annual SRO Exam A3, 11/25/16

Procedures:
SEI-01, Rev 4, Simulator Fidelity and Performance Standard
SEI-07, Rev 7, Simulator Operability Testing and Evaluation
TR-AA-220-1004, Rev. 2, Licensed Operator Continuing Training Annual Operating and

Biennial Written Exams
TR-AA-220-1002, Rev. 3, NRC Licensed Operator Exam Security
TR-AA-230-1000, Rev. 0, Systematic Approach To Training Process
TR-AA-230, Rev. 4, Systematic Approach To Training
TR-AA-230-1007, Rev. 5, Conduct of Simulator Training and Evaluation

TR-AA-230-1009, Rev. 1, Simulator Scenario Based Testing and Validation
TR-AA-104, Rev. 9, NEXTERA ENERGY Fleet Licensed Operator Continuing Training Program

Simulator Steady State Tests:
30% Steady State Test, Cycle 22
50% Steady State Test, Cycle 22

Simulator Normal Evolution Tests:
PSL OPS 0814054, Shutdown Cooling, 2/13/17
PSL OPS 0814036, Turbine Rollup, Synchronization, Power Ascension, 3/19/17

Simulator Transient Tests:
Cycle 22 Transient Test TRN-001, Reactor Trip, Rev 11, 8/9/17
Cycle 22 Transient Test TRN-004, Loss of Al RCPs from Full Power, Rev 9, 8/9/17
Cycle 22 Transient Test TRN-009, Double Ended Main Steam Line Break Inside Containment, Rev 10, 8/9/17

Simulator Scenario Based Tests:
0815018, Rev 20, LOCA with Loss of AFW
0815006, Rev 22, Feed Line Break with TLOF

Closed Simulator Service Requests:
AR 02193047-01, Simulator – Response to Steam Leak Not as Expected
AR 022066338-01, Simulator Issues Occurring During PSL OPS
AR 02144901-01, Simulator Spurious Alarms for Low Vacuum and Turbine Trip
AR 02157151-01, Simulator Modeling – Plant Vent

Scenario Packages:
Simulator Exercise Guide 0815018, Rev. 20
Simulator Exercise Guide 0815048, Rev.06
Simulator Exercise Guide 0815025, Rev.01
Simulator Exercise Guide 0815053, Rev.01

JPM Packages:
PSL OPS 0821034, Rev. 18
PSL OPS 0821112T, Rev. 13
PSL OPS 0821211, Rev. 02
PSL OPS 0821025A, Rev. 14
PSL OPS 0821051A, Rev. 17
PSL OPS 0821004, Rev. 15
PSL OPS 0821018A, Rev. 20
PSL OPS 0821129, Rev. 13
PSL OPS 0821305A, Rev. 01
PSL OPS 0821033, Rev. 20

Condition Reports:
AR 02170034, Adverse Trend Simulator Issues
AR 02100051, Sim JPM did not Work During Annual Operating Exam
AR 02124429, Simulator Problem Causing LOCT Schedule Change
AR 02165786, Potential Adverse Trend Simulator Issues
AR 02229387, Gap in JPM Overlap Identified During Pre-71111.11B
AR 02229390, Gap in Remediation Documentation During Pre-71111.11B
AR 02233651, 2017 AOE Lessons Learned
AR 02142815, Documentation of an Operations HU Event

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
AR 2233027, Perform MR evaluation for AR 2160784, HVS-1B breaker trip
System Health Report: System 25a, HVAC (risk significant)

Section 1R13: Maintenance Risk Assessments and Emergent Work Control
OP-AA-104-1007, Online Aggregate Risk
WCG-016, Online Work Management

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

Section 1R17: Operability Determinations and Functionality Assessments
See Section 4OA5
Section 4OA2: Identification and Resolution of Problems

3rd Quarter 2017 Self-Evaluation and Trending Analysis Report - Maintenance
3rd Quarter 2017 Self-Evaluation and Trending Analysis Report - Engineering
3rd Quarter 2017 Self-Evaluation and Trending Analysis Report - Operations
3rd Quarter 2017 Self-Evaluation and Trending Analysis Report - Radiation Protection
3rd Quarter 2017 Self-Evaluation and Trending Analysis Report – Station
3rd Quarter 2017 Self-Evaluation and Trending Analysis Report – Security
3rd Quarter 2017 Self-Evaluation and Trending Analysis Report – Training
3rd Quarter 2017 Self-Evaluation and Trending Analysis Report – Chemistry

AR 2136375, CEA-60 transferred to its lower gripper (June 6, 2016)
AR 2176633, CEA-91 transferred to its lower gripper (December 25, 2016)
AR 2213698, CEA-60 transferred to its lower gripper (July 6, 2017)
AR 2231391, CEA-53 transferred to its lower gripper (October 19, 2017)
AR 2238436, CEA-49 transferred to its lower gripper (November 30, 2017)
AR 2241639, CEA-60 transferred to its lower gripper (December 20, 2017)

Section 4OA3: Followup of Events and Notices of Enforcement Discretion
Procedures
OP-0030119, Post Trip Review
2-EOP-01, Standard Post Trip Actions
2-EOP-02, Reactor Trip Recovery

<u>Section 4OA5: Other Activities</u>

<u>Corrective Action Documents Written as a Result of the Inspection</u>
AR 2216120, 2017 NRC 5059 Inspection URI- Unit 1 Hot Leg Injection Jumper
AR 2217631, U1 Hot Leg Injection Procedures

<u>Procedures</u>
Emergency Procedure 0120042, Loss of Reactor Coolant, Rev. 19
EN-AA-203-1202, 10 CFR 50.59 Evaluation, Rev. 1
EPIP-05, Activation and Operation of the Operational Support Center, Rev. 36
1-GME-100.03, Installation and Removal of Temporary Power Jumpers for MOV V3481 and V3652, Rev. 5
1-GME-100.03A, Installation and Removal of Temp Power Jumpers for HCV-3615, 3625, 3635, 3645, MV-03-1A, MV-03-1B, Rev. 3
1-EOP-99, Appendices/Figures/Tables/Data Sheets, Rev. 42

<u>Drawings</u>
8770-G-071, Sheet 3, General Arrangement Reactor Auxiliary Building Plan, Rev. 31
8770-B-327, Sheet 250, Control Wiring Diagram Shutdown Cooling Isolation Valve V-3481, Rev. 12
8770-B-327, Sheet 140, Control Wiring Diagram Measurement Channels L-1103, L-1116 & P-1103, Rev. 21
8770-B-327, Sheet 394, Control Wiring Diagram RTGB-103 & 104- 120V AC & 125V DC Distribution, Rev. 23
8770-B-327, Sheet 648, Control Wiring Diagram RTGB-106- 120V AC & 125V DC Distr- SH2, Rev. 24

<u>Miscellaneous Documents</u>
NAI-2016-001, St. Lucie Unit 1 Post-LOCA Mission Dose- Hot Leg Injection Jumpers, Rev. 0
EC 284437, Evaluation of Actions Required to Mitigate Hot Leg Injection Single Failure Vulnerability, Rev. 0
Supplement No. 2 to the Safety Evaluation of the St. Lucie Plant Unit No. 1, Docket No. 50-335, dated 3/1/76
Letter dated March 29, 1982, C. Nelson (NRC) to R. Uhrig (FPL) with Enclosure, “St. Lucie Unit 1 Post-LOCA Boron Concentration Control” (ADAMS ML17212B492)
Memorandum dated January 21, 1975, T. Novak (NRC) to K. Parczewski (NRC) with Attachment, “Concentration of Boric Acid in Reactor Vessel during Long Term Cooling-Method for Reviewing Appendix K Submittals” (ADAMS 8107020118)
Branch Technical Position ICSB 18 (PSB), Application of the Single Failure Criterion to Manually- Controlled, Electrically-Operated Valves, Rev. 2, July 1981
Licensee Event Report 05000335/2011-003-01, Long-Term Post-LOCA Hot Leg Injection Single Failure Vulnerability
PSL-ENG-SEMS-17-007, St. Lucie Unit 1 Hot Leg Injection FMEA, Rev. 0

<u>Procedures</u>
1-NOP-116.01, Dry Shielded Canister Fuel Loading
0-GMM-116.07, ISFSI TC/DSC Preparation For Loading
0-GMM-116.08, ISFSI TC/DSC Handling Operations For Fuel Loading
0-GMM-116.12, ISFSI Dry Shielded Canister Sealing Operations
0-GMM-116.14, ISFSI DSC Transport From CHF to HSM

Radiation Protection Plan 2017-2018 ISFSI Dry Fuel Loading Campaign
RP-SL-103-1003, ISFSI Radiological Controls
WO 4521942-57, Move U1 SP Fuel to Type 2 DSC 083 to HSM-31
Final Safety Evaluation Report NUHOMS HD Horizontal Modular Storage (Docket 72-1030, Amendment No. 2)
NUHOMS HD System Generic Technical Specifications Amendment 2 (App. A to CoC No. 1030)
0010434, Plant Fire Protection Guidelines
0010438, Control of Heavy Load

LIST OF ACRONYMS

ADAMS	NRC's Agency-wide Documents Access and Management System
ADM	Administrative Procedure
AFW	Auxiliary Feedwater
AFAS	Auxilliary Feedwater Actuation System
AOP	Abnormal Operating Procedure
AR	Action Request
AC	Alternating Current
BTU	Bistable Trip Unit
CAP	Corrective Action Program
CCW	Component Cooling Water
CEA	Control Element Assembly
CFR	Code of Federal Regulations
CoC	Certificate of Compliance
CS	Containment Spray
DEH	Digital Electrohydraulic
DSC	Dry Shielded Cask
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
FCV	Flow Control Valve
FPL	Florida Power and Light
FT	Flow Transmitter
GOP	General Operating Procedure
HPSI	High Pressure Safety Injection
HSUR	High Startup rate
HVAC	Heating, Ventilation and Air Conditioning
HX	Heat Exchanger
I&C	Instrument and Control
IMC	Inspection Manual Chapter
ICW	Intake Cooling Water
IP	Inspection Procedure
ISFSI	Independent Spent Fuel Storage Installation
LCO	Limiting Condition for Operation
LIV	Licensee-Identified Violation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LPSI	Low Pressure Safety Injection
MFIV	Main Feedwater Isolation Valve
MR	Maintenance Rule (10 CFR 50.65)
MSPI	Mitigating System Performance Indicators
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NI	Nuclear Instrument
NOP	Normal Operating Pressure
NRC	Nuclear Regulatory Commission
OLRM	Online Risk Monitor
OOS	Out of Service

OSP	Operations Surveillance Procedure
PARS	Publically Available Record
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PSL	Plant St. Lucie
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
RP	Radiation Protection
RPS	Reactor Protection System
RTP	Rated Thermal Power
RWT	Refueling Water Tank
SDP	Significance Determination Process
SG	Steam Generating
SMI	Surveillance Maintenance Procedure
SSC	Systems, Structures, and Components
TCV	Temperature Control Valve
TI	Temporary Instruction
TS	Technical Specification
UT	Ultrasonic Test
UFSAR	Updated Final Safety Analysis Report
WO	Work Order
WR	Work Request