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

June 1, 2012

Mr. Mano Nazar
Executive Vice President and Chief Nuclear Officer
Florida Power & Light Company
P.O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: ST. LUCIE NUCLEAR PLANT – NRC PROBLEM IDENTIFICATION AND RESOLUTION INSPECTION REPORT 05000335/2012007 AND 05000389/2012007

Dear Mr. Nazar:

On April 20, 2012, the U. S. Nuclear Regulatory Commission (NRC) completed a Problem Identification and Resolution biennial inspection at your St. Lucie Nuclear Plant Units 1 and 2. The enclosed report documents the inspection results, which were discussed on April 20, 2012, with Mr. R. Anderson and other members of your staff.

The inspection was an examination of activities conducted under your license as they relate to the problem identification and resolution, compliance with the Commission's rules, regulations, and with the conditions of your license. Within these areas, the inspection involved examination of selected procedures, representative records, observations of plant equipment and activities, and interviews with personnel.

Based on the inspection sample, the inspection team concluded that the implementation of the corrective action program and overall performance related to identifying, evaluating, and resolving problems at St. Lucie was adequate. Licensee identified problems were entered into the corrective action program at a low threshold. Problems were generally prioritized and evaluated commensurate with the safety significance of the problems. Corrective actions were generally implemented in a timely manner commensurate with their importance to safety and addressed the identified causes of problems. Lessons learned from the industry operating experience were generally reviewed and applied when appropriate. Audits and self-assessments were effectively used to identify problems and appropriate actions. However, during the inspection, the team identified several performance deficiencies related to prioritization and evaluation of identified problems, and the use of operating experience including information provided in vendor manuals.

The enclosed inspection report discusses one self-revealing apparent violation (AV) associated with inadequate preventative maintenance of the immersion heater for the Unit 1 safety-related Emergency Diesel Generator (EDG). This violation has potential safety significance greater than very low safety significance (Green). However the violation does not represent an immediate safety concern because the immersion heater was replaced and the EDG was successfully returned to service. The violation results in the need for further evaluation to determine significance and therefore the need for additional NRC action. The AV with the supporting circumstances and details is documented in the enclosed report.

In addition, two NRC-identified findings and two self-revealing findings of very low safety significance (Green) were identified during this inspection. One of these findings was determined to involve a violation of NRC requirements. Furthermore, one licensee-identified violation which was determined to be of very low safety significance is listed in this report. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2 of the NRC Enforcement Policy because of the very low safety significance of the violations and because they are entered into your corrective action program. If you contest these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; 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 facility. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region II, and the NRC Resident Inspector at St. Lucie.

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

Sincerely,

/RA/

George T. Hopper, Chief
Reactor Projects Branch 7
Division of Reactor Projects

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

Enclosure: Inspection Report 05000335/2012007,
05000389/2012007
w/Attachment: Supplemental Information

cc w/encl. (see page 2)

successfully returned to service. The violation results in the need for further evaluation to determine significance and therefore the need for additional NRC action. The AV with the supporting circumstances and details is documented in the enclosed report.

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George T. Hopper, Chief
Reactor Projects Branch 7
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Docket Nos.: 50-335, 50-389
License Nos.: DPR-67, NPF-16

Enclosure: Inspection Report 05000335/2012007,
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cc w/encl. (see page 2)

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Letter to Mano Nazar from George T. Hopper dated June 1, 2012

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No.:	50-335, 50-389
License No.:	DPR-67, NPF-16
Report No:	05000335/2012007, 05000389/2012007
Licensee:	Florida Power & Light Company (FP&L)
Facility:	St. Lucie Nuclear Plant, Units 1 & 2
Location:	6351 South Ocean Drive Jensen Beach, FL 34957
Dates:	April 2 - 6, 2012 April 16 - 20, 2012
Inspectors:	T. Morrissey, Senior Resident Inspector, Crystal River, Team Leader T. Chandler, Resident Inspector, Vogtle R. Ng, Senior Project Engineer, Region III J. Reyes, Resident Inspector, St. Lucie J. Sowa, Resident inspector, Farley R. Taylor, Senior Project Engineer, Region II
Approved by:	G. Hopper, Chief, Reactor Projects Branch 7 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000335/2012007, 05000389/2010007; 04/02/2012 – 04/20/2012; St. Lucie Nuclear Plant, Units 1 and 2; Identification and Resolution of Problems.

The inspection was conducted by a senior resident inspector, two senior project engineers, and three resident inspectors. One apparent violation (AV), one Green non-cited violation (NCV), and three Green findings were identified. The significance of most findings is identified by their color (Green, White, Yellow, Red) using IMC 0609, Significance Determination Process (SDP); cross-cutting aspects were determined using IMC 0310; Components Within the Cross-Cutting Areas (CCA); and findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, Reactor Oversight Process (ROP).

Identification and Resolution of Problems

The team concluded that, in general, problems were properly identified, evaluated, prioritized, and corrected. The threshold for initiating Condition Reports (CRs) in the corrective action program (CAP) was appropriately low, as evidenced by the types of problems identified and the number of CRs entered annually into the CAP. However, the team did identify deficiencies in the area of prioritization and evaluation of identified problems and the use of operating experience, including the use of vendor recommended preventative maintenance information. Licensee 2011 performance improvement audit results were in line with the team's observations and findings. The audit documented examples of items in the CAP not being corrected and closed in a complete, timely and accurate manner.

The team determined that audits and self-assessments were adequate in identifying deficiencies and areas for improvement in the CAP, and appropriate corrective actions were developed to address the issues identified.

Based on discussions and interviews conducted with plant employees from various departments, the team determined that personnel at the site felt free to raise safety concerns to management and use the CAP to resolve those concerns. However, the number and content of anonymous ARs indicates that some plant personnel are reluctant to identify themselves.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

TBD: A self revealing potentially greater than Green AV of Technical Specification 6.8.1.a was identified for failure to establish adequate maintenance procedures associated with the emergency diesel generator (EDG) system. Specifically, station personnel failed to establish preventative maintenance inspections of diesel immersion heaters in accordance with vendor manual recommendations. As a result, the Unit 1 1A EDG was immediately rendered inoperable for 43.5 hours due to a failed immersion heater that resulted in a leak of the 1A2 EDG jacket water system. The licensee replaced the heater with an onsite spare.

The finding was considered more than minor because it impacted the Reactor Safety Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences and affected the cornerstone attribute of equipment performance. The issue was placed in the licensee's corrective action program as condition report 1751214.

The cause of this finding was related to the Work Control component of the Human Performance cross-cutting area due to the failure to plan work activities to ensure long term equipment availability. Specifically, maintenance scheduling was more reactive than preventative. [H.3(b)] (Section 4OA2.b(3)(i))

Green: An NRC-identified Green NCV of 10 CFR Part 50 Appendix B, Criterion XVI, Corrective Actions was identified for the licensee's failure to correct an identified condition adverse to quality associated with Low Pressure Safety Injection (LPSI) pump casing distortion. Specifically, the licensee failed to implement corrective actions to address an identified LPSI pump design deficiency, which resulted in failure of the 2A LPSI pump in March 2009. This issue was documented in the licensee's corrective action program as condition report 2009-16124.

This finding was more than minor because it was associated with the equipment reliability attribute of the Mitigating Cornerstone and it adversely affected the associated 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, the failure to correct the LPSI pump design deficiency impacts the availability, reliability, and capability of the LPSI system to respond to plant events. In accordance with NRC Inspection Manual Chapter 0609.04, Significant Determination Process – Phase 1 screening, the finding was determined to be of very low safety significance (Green) because the finding did not result in a loss of system safety function or a loss of safety function of a single train for greater than allowed Technical Specification allowed outage time. The finding did not represent an actual loss of safety function for greater than its technical specification allowed outage time.

The finding had a cross-cutting aspect in the area of work practices, resources because the licensee failed to ensure that equipment is available and adequate to assure nuclear safety. Specifically, the licensee failed to maintain long term plant safety by minimizing longstanding LPSI pump design issues. [H.2(a)] (Section 4OA2.a(3)(ii))

Cornerstone: Initiating Events

Green: A self-revealing finding was identified for the licensee's failure to implement vendor recommended preventive maintenance requirements to monitor and trend motor stator temperatures using the installed resistance temperature detector (RTDs) for the 1A2 Circulating Water Pump (CWP) motor. As a result of not trending 1A2 CWP motor performance, the pump was allowed to run to failure causing an unplanned reactor power transient. No violation of NRC regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because the performance deficiency involved non-safety related equipment. The licensee entered this issue in the corrective action program as condition report 1758355. Corrective actions included revising the circulating pump motor preventive maintenance procedure to include periodic monitoring and trending circulating water pump motor thermal performance using the installed stator Resistance Temperature Detectors (RTDs).

The finding was more than minor because it affected the equipment reliability attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using NRC Manual Chapter 0609.04, SDP – Phase 1 screening, the finding was determined to be of very low safety significance (Green) because it was a transient initiator, but did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The finding did not have a cross-cutting aspect because the performance deficiency was not indicative of current plant performance. (Section 4OA2.b(3)(ii))

Green: A self-revealing finding was identified for the licensee's failure to implement timely corrective actions. Specifically, after the overheating and failure of a Circulating Water Pump (CWP) motor resulted in an unplanned reactor down power, the licensee failed to implement timely corrective actions to monitor and trend motor stator temperatures using the installed RTDs. Consequently, a second CWP motor failed due to overheating that resulted in a reactor trip. No violations of NRC requirements were identified because the performance deficiency involved non-safely related equipment. The licensee entered this issue in the corrective action program as condition report 1697977. Corrective actions included immediately taking the motor stator RTD temperatures on both Units and using that data to monitor the CWP motors thermal performance for degradation.

The finding was more than minor because it affected the equipment reliability attribute of the Initiating Events Cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using NRC manual Chapter 0609.04, SDP – Phase 1 screening, the finding was determined to be of very low safety significance (Green) because it was a transient initiator, but did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The finding involved the cross-cutting area of Problem Identification and Resolution with a corrective action program aspect. Specifically, the licensee did not take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity. [P.1(d)] (Section 4OA2.a(3)(iii))

Green: An NRC identified finding was identified for the licensee's failure to perform a preventive maintenance (PM) activity within its prescribed frequency on the 1B condensate pump discharge check valve. Consequently, the valve failed after a reactor trip and caused complications. No violations of NRC requirements were identified because the condensate pump discharge valve is non-safety related. The licensee entered this issue in the corrective action program as condition report 1755189.

Corrective actions included revising the preventive maintenance procedure to initiate a condition report and require plant management approval prior to rescheduling a late PM. The finding was more than minor because it affected the equipment reliability attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using NRC manual Chapter 0609.04, Significant Determination Process – Phase 1 screening, the finding was determined to be of very low safety significance (Green) because it was a transient initiator, but did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The finding involved the cross-cutting area of Human Performance with a work control aspect. Specifically, the licensee did not plan work activities to support long-term equipment reliability, and maintenance scheduling was more reactive than preventive. [H.3(b)] (Section 4OA2.a(3)(i))

B. Licensee Identified Violations

One violation of very low safety significance was identified by the licensee and has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the corrective action program. The violation and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

4. OTHER ACTIVITIES

4OA2 Problem Identification and Resolution

a. Assessment of the Corrective Action Program (CAP)

(1) Inspection Scope

The team reviewed the licensee's CAP procedures which described the administrative process for initiating and resolving problems primarily through the use of condition reports (CRs). To verify that problems were being properly identified, appropriately characterized, and entered into the CAP, the team reviewed a sample of CRs that had been issued between March 2010 and March 2012, including a detailed review of selected CRs associated with the following risk-significant systems and components: Low Pressure Safety Injection (LPSI), Engineered Safeguards (ES) 4160V AC busses, High Pressure Safety Injection (HPSI) check valves, Emergency Diesel Generators (EDGs) and safety related electrical relays. Where possible, the team independently verified that the corrective actions were implemented as intended. The team also reviewed selected common causes and generic concerns associated with root cause evaluations (RCE) to determine if they had been appropriately addressed. To help ensure that samples were reviewed across all cornerstones of safety identified in the NRC's Reactor Oversight Process (ROP), the team selected a representative number of CRs that were identified and assigned to the major plant departments, including operations, maintenance, engineering, health physics, chemistry, emergency preparedness and security. These CRs were reviewed to assess each department's threshold for identifying and documenting plant problems, thoroughness of evaluations, and adequacy of corrective actions. The team reviewed selected CRs, verified corrective actions were implemented, and attended meetings where CRs were screened for significance to determine whether the licensee was identifying, accurately characterizing, and entering problems into the CAP at an appropriate threshold.

The team conducted plant walkdowns of equipment associated with the selected systems and other plant areas to assess the material condition and to look for any deficiencies that had not been previously entered into the CAP. The team reviewed CRs, maintenance history, completed work orders (WOs) for the systems, and reviewed associated system health reports. These reviews were performed to verify that problems were being properly identified, appropriately characterized, and entered into the CAP. Items reviewed generally covered a two-year period of time; however, a five-year review was performed for selected systems for age-dependent issues.

Control room walkdowns were also performed to assess the main control room (MCR) deficiency list and to ascertain if deficiencies were being tracked to resolution. A sample of operator workarounds and operator burden screenings were reviewed and the team verified compensatory measures for deficient equipment were being implemented in the field.

The team conducted a detailed review of selected CRs to assess the adequacy of the root-cause and apparent-cause evaluations of the problems identified. The team reviewed these evaluations against the descriptions of the problem described in the CRs and the guidance in licensee procedure PSL-01.05, Apparent Cause Evaluation (ACE) Handbook and PSL-01.06, Root Cause Evaluation Handbook. The team assessed if the licensee had adequately determined the cause(s) of identified problems, and had adequately addressed operability, reportability, common cause, generic concerns, extent-of-condition, and extent-of-cause. The review also assessed if the licensee had appropriately identified and prioritized corrective actions to prevent recurrence.

The team reviewed corrective actions that were completed after the conclusion of the NRC supplemental inspection associated with the Unit 1 Component Cooling Water system air intrusion event (NRC Supplemental Inspection Report 05000335/2010009) to ensure those corrective actions were sufficient to address the root and contributing causes and prevent recurrence.

The team reviewed selected industry operating experience items, including NRC generic communications and Part 21 reports, to verify that they had been appropriately evaluated for applicability or used in licensee activities and that issues identified through these reviews had been entered into the CAP.

The team reviewed site trend reports to determine if the licensee effectively trended identified issues and initiated appropriate corrective actions when adverse trends were identified.

The team attended various plant meetings to observe management oversight functions of the corrective action process. These included CR Initial Screening Team (IST) meetings and Management Review Committee (MRC) meetings.

Documents reviewed are listed in the Attachment.

(2) Assessment

Identification of Issues

The team determined that the licensee was generally effective in identifying problems and entering them into the CAP and there was a low threshold for entering issues into the CAP. This conclusion was based on a review of the requirements for initiating CRs as described in licensee procedure PL-SL-204, Condition Identification and Screening Process, management's expectation that employees were encouraged to initiate CRs for any reason, and the relatively few number of deficiencies identified by team during plant walkdowns not already entered into the CAP. Trending was generally effective in monitoring equipment performance. Site management was actively involved in the CAP and focused appropriate attention on significant plant issues. Based on reviews and walkdowns of accessible portions of the selected systems, the team determined that system deficiencies were identified and placed in the CAP.

The team had two observations related to identification of issues. These observations were screened in accordance with Manual Chapter 0612, Issue Screening, and were determined to be of minor significance and not subject to enforcement action in accordance with the NRC's Enforcement Policy.

- Through discussions with plant system engineers, the team noted that some less experienced system engineers were not fully utilizing existing tools such as the system health reports to track and trend overall status of their associated systems. Specifically, when asked, some engineers were unaware of current trends such as the number of outstanding work orders on their systems.

- The team identified that preventative maintenance (PM) for the 1B condensate pump discharge check valve had been deferred twice past its late date without placing the issue into the CAP. The licensee implemented changes to their preventative maintenance procedures in November 2011 that required a CR to be written for PMs that are overdue, and plant general manager approval to scheduling PMs past the due date. A finding associated with this check valve failure is documented in Section 4OA2.a(3)(i) of the report.

<u>Prioritization and Evaluation of Issues</u>

Based on the review of CRs sampled by the inspection team during the onsite period, the team concluded that problems were generally prioritized and evaluated in accordance with the licensee's CAP procedures as described in the CR severity level determination guidance in procedure PL-SL-204. Each CR was assigned a severity level at the IST meeting, and adequate consideration was given to system or component operability and associated plant risk.

The team determined that station personnel had conducted root cause and apparent cause analyses in compliance with the licensee's CAP procedures and assigned cause determinations were appropriate, considering the significance of the issues being evaluated. A variety of formal causal-analysis techniques were used depending on the type and complexity of the issue consistent with procedures PSL-01.05 and PSL-01.06.

The team identified several performance deficiencies associated with the licensee's prioritization and evaluation of issues. These issues were screened in accordance with Manual Chapter 0612, Issue Screening, and were determined to be of minor significance and not subject to enforcement action in accordance with the NRC's Enforcement Policy.

- The team identified that a corrective action to prevent recurrence (CAPR) associated with CR 565918 was inappropriately closed to a work order that was then cancelled. The licensee initiated CR 1752272 to address this issue.

- The team identified that CAPR associated with CR 584721 was inappropriately closed to a procedure revision request. The licensee initiated CR 1752303 to address this issue.

- In reviewing CR 1679935, associated with a Unit 1 trip, the team identified that the licensee did not perform an evaluation of a trip of the Unit 1 1A Main Feedwater pump after the 1B condensate pump was secured. The licensee initiated CR 1755189 to address this issue.

- In reviewing CR 1679935, associated with a Unit 1 trip, the team identified that the licensee had not evaluated the stuck open 1B condensate pump discharge check valve as an operator work around and also did not provide written instructions on plant operations with the degraded check valve. The licensee initiated CRs 1755190 and 1755191 to address these issues.

Effectiveness of Corrective Actions

Based on a review of corrective action documents, interviews with licensee staff, and verification of completed corrective actions, the team determined that generally, corrective actions were timely, commensurate with the safety significance of the issues, and effective, in that conditions adverse to quality were corrected and non-recurring with the exception of those issues identified in this report. For significant conditions adverse to quality, the corrective actions directly addressed the cause and effectively prevented recurrence in that a review of performance indicators, CRs, and effectiveness reviews demonstrated that the significant conditions adverse to quality had not recurred. Effectiveness reviews for CAPRs were sufficient to ensure corrective actions were properly implemented and were effective. However, the team determined that evaluation deficiencies discussed in the previous section of the report rendered the corrective actions ineffective for those issues.

In addition to the findings documented below, the team identified a licensee-identified violation associated with the effectiveness of corrective actions. During the review of Licensee Event Report (LER) 05000335/2011-003, Long-Term Post LOCA Hot Leg Injection Single Failure Vulnerability, the team noted that corrective actions identified in 1999 were not implemented until 2011. Additional details and the regulatory significance of this issue is documented in section 4OA7 of this report.

A licensee 2011 performance improvement audit results were in line with the team's observations and findings. The audit documented examples of items in the CAP not being corrected and closed in a complete, timely and accurate manner.

(3) Findings

i. Failure To Perform Preventive Maintenance On The 1B Condensate Pump Discharge Check Valve

Introduction: A Green NRC-identified finding was identified for the licensee's failure to perform a PM activity in accordance with procedure 0010431, Preventive Maintenance Program, within its prescribed frequency on the 1B condensate pump (CDP) discharge check valve. Immediately following a Unit 1 trip, the 1B CDP discharge check valve failed open when its respective pump was secured, causing suction pressure to the main feedwater system to decrease. As a result, both main feedwater (MFW) pumps tripped, due to low suction pressure, resulting in complications after the reactor trip.

Description: On August 22, 2011 during a significant influx of jellyfish into the intake structure, the Unit 1 control room operators entered abnormal operating procedure 1-AOP-21.01, Circulating Water System, to initiate throttling the Circulating Water Pump (CWP) flow due to high differential pressures across the intake traveling water screens. Shortly thereafter, the operators entered AOP-21.01, Rapid Down Power, to reduce reactor power due to decreasing condenser vacuum. During the down power, the 1A2 traveling water screen tripped and the 1A2 CWP was then secured when the differential pressure across the 1A2 traveling water screen exceeded procedural limits. Subsequently, due to a continuing decrease in condenser vacuum, Unit 1 was manually tripped before reaching the automatic trip set point for low condenser vacuum. Immediately following the trip, the 1B MFW pump was secured due to reports from the field of a casing leak on that pump. The 1B CDP was then secured but its pump discharge check valve failed to close causing the running 1A MFW pump to trip on low suction pressure. The 1B MFW pump automatically restarted but then tripped on low suction pressure as well. The 1B CDP was reported rotating backwards. The auxiliary feedwater pumps were started to control and maintain steam generator water levels. Additionally, during the performance of standard post trip actions in procedure 1-EOP-01, a power range nuclear instrument (NI) failed low.

A root cause team investigated the issues that lead to the reactor trip and the conclusions were documented in CR 1679935. The root cause charter described that separate condition reports were to be generated for the 1B MFW pump casing leak, 1A MFW pump trip, 1B condensate pump check valve issue (pump rotating backwards) and the power range NI failure. The inspectors found that no condition reports had been written for the failed equipment as described in the root cause charter. The licensee acknowledge the issue of not having written condition reports as described by the root cause charter and initiated condition report 1755189 to address this issue.

The inspectors reviewed the maintenance history on the 1B CDP discharge check valve and found that at the time of the failure, maintenance on the check valve had not been performed as required by the PM program. A PM was scheduled to be performed on the check valve every six years. The six year PM performed on the check valve included a comprehensive inspection, disassembly, repair, and assembly of the check valve. The PM had not been performed since 2002. In January 2009 after the PM frequency had been exceeded, the PM was deferred to December 2010. In December 2010 the PM was deferred a second time to November 2011 during the unit refueling outage. The PM was completed February 2012. In reviewing the extent of condition on the late PM, the inspector found that a similar check valve, 2A CDP discharge check valve, on the Unit 2 condensate system had also exceeded its six year PM frequency and had last been performed in May 2003. The licensee initiated CR 1756412 to review the PM scheduling of the remainder of the condensate system check valves to ensure the PM would be completed during the outage windows.

Analysis: The inspectors determined that the failure to perform the maintenance on the 1B CDP discharge check valve within its PM frequency as required by procedure 00100431, Preventative Maintenance Program, was a performance deficiency. The inspectors determined that the performance deficiency was more than minor because it affected the equipment reliability attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using NRC Inspection Manual Chapter (IMC) 0609.04, Significant Determination Process (SDP) – Phase 1 screening, the finding was determined to be of very low safety significance (Green) because it was a transient initiator, but did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The finding involved the cross-cutting area of Human Performance with a work control aspect. Specifically, the licensee did not plan work activities to support long-term equipment reliability, and maintenance scheduling was more reactive than preventive [IMC 0310, H.3(b)].

Enforcement: No violation of NRC regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because the performance deficiency involved non-safety related equipment. This finding was determined to be of very low safety significance (Green) and was entered into the licensee's CAP as CR 1755189. This finding is identified as FIN 05000335/2012007-01, Failure to Perform Preventive Maintenance on the 1B Condensate Pump Discharge Check Valve.

ii. Failure to Correct a Low Pressure Safety Injection (LPSI) Pump Design Deficiency

Introduction: An NRC-identified Green non-cited violation (NCV) of 10 CFR Part 50 Appendix B, Criterion XVI, Corrective Actions was identified for the licensee's failure to correct an identified condition adverse to quality associated with LPSI pump casing distortion. Specifically, the licensee failed to implement corrective actions to address an identified LPSI pump design deficiency, which resulted in failure of the 2A LPSI pump in March 2009. This issue was documented in the licensee's corrective action program as CR 2009-16124.

Description: The team reviewed the corrective action history associated with the 2A LPSI pump.

- In 1996, Westinghouse Technical Bulletin ESBU-TB-96-03-RO and other industry operating experience reports documented seizures of Ingersoll-Rand Model 8x20 WDF pumps operating as Westinghouse residual heat removal (RHR) pumps due to thermal distortion of the pump stuffing box extensions. The licensee believed that this industry-operating experience was only applicable to Westinghouse RHR pumps due to the much larger temperature transients experienced in those applications. Westinghouse and Ingersoll-Dresser proposed a stuffing box extension structural design improvement.

- In 1997, the licensee found 2A LPSI pump with a locked rotor condition during performance of 2-OP-0400050, Periodic Test of Engineered Safety Features. The cause of the failure was investigated and could not be determined. Based on the reassembled pump performing acceptably during the spring 1997 refueling outage, the pump was returned to service. However, after subsequent review of the locked rotor condition, the cause was determined to be distortion of the casing.

- In 2006, the licensee determined that the 2A LPSI pump upper wear ring clearances had unexpectedly decreased and it was then recognized that the stuffing box extension distortion was applicable to St. Lucie Unit 2 LPSI pumps. CR 2006-14726 documented that during the replacement of the 2A LPSI pump mechanical seal, the upper wear ring clearance was found to be less than the minimum specified in the vendor technical manual. This was unexpected as wear ring clearances normally increase with service time. Corrective actions were taken to restore the wear ring clearances. The licensee suspected in 2006, and subsequently confirmed in 2009, that the reduced wear ring clearances could be a symptom that the stuffing box extension was gradually becoming distorted. The 1996 Westinghouse Technical Bulletin was reviewed and it was determined that the pump manufacturer had developed a retrofit modification to address stuffing box extension distortion. This design modification, CAR 06-074, was presented to the plant health committee and approved. However, the modification was not funded and was listed in the CAR database with a low implementation priority.

- In 2009, the 2A LPSI pump was again found with a locked rotor condition during plant heat up at the end of a unit outage. The inspection of the pump found that the clearance between the stuffing box extension and the casing was significantly oversized compared to the designed dimension. This discrepancy would allow the impeller to be positioned off center relative to the wear ring and increase the potential for contact. The pump seizure was determined to be caused by excessive clearance between the stuffing box extension and case which allowed the impeller to be located off-center in the case wear ring. When exposed to operating loads, deflection of the impeller resulted in contact with the casing and seizure. Corrective actions included:

    The stuffing box extension was replaced and the case was machined to restore clearances to acceptable values.

    Procedures for maintaining this type of pump were revised to assure that the clearance between the stuffing box extension and the case is measured when the pump is disassembled and within the manufacturers tolerance.

    The 2B LPSI pump cover to case clearance was inspected and restored during the following outage.

    A 9-year PM was established to disassemble and inspect the Unit 2 LPSI pumps.

Corrective action to prevent recurrence was to implement CAR 06-074 for the 2A and 2B LPSI pump coupling retrofit which includes pump casing structural thermal design improvement.

The team determined that the licensee failed to correct a condition adverse to quality, identified in 2006, associated with LPSI pump casing distortion, which could have precluded the 2009 failure of the 2A LPSI pump.

Analysis: The licensee's failure to correct an identified condition adverse to quality associated with LPSI pump casing distortion, which resulted in failure of the 2A LPSI pump in March 2009, was a performance deficiency. Specifically, the licensee failed to implement corrective actions to address an identified LPSI pump design deficiency. This performance deficiency was more than minor because it was associated with the equipment reliability attribute of the Mitigating Systems Cornerstone and it adversely affected the associated 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, the failure to correct the LPSI pump design deficiency impacts the availability, reliability, and capability of the LPSI system to respond to plant events. In accordance with NRC Inspection Manual Chapter 0609.04, Significant Determination Process – Phase 1 screening, the finding was determined to be of very low safety significance (Green) because the finding did not result in a loss of system safety function or a loss of safety function of a single train for greater than allowed technical specification allowed outage time and the finding did not represent an actual loss of safety function for greater than the identified technical specification allowed outage time.

The team determined that this finding had a cross-cutting aspect in the area of work practices, resources [IMC 0310, Aspect H.2(a)] because the licensee failed to ensure that equipment was available and adequate to assure nuclear safety. Specifically, the licensee failed to maintain long term plant safety by minimizing longstanding LPSI pump design issues.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI requires, in part, that conditions adverse to quality be promptly identified and corrected. Contrary to the above, since 2006, the licensee failed to correct an identified condition adverse to quality involving a LPSI pump design deficiency. The licensee entered the issue into the corrective action program as CR 2009-16124. Because this violation was of very low safety significance, and it was entered into the licensee's corrective action program, this violation was treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. This violation is designated as NCV 05000389/2012007-02, Failure to Correct a LPSI Pump Design Deficiency.

iii. Failure to Implement Timely Corrective Actions Resulted in a Plant Trip

Introduction: A Green self-revealing finding was identified for the licensee's failure to implement timely corrective actions in accordance with CAP procedure PI-SL-205 Condition Evaluation and Corrective Actions. Specifically, after the overheating and failure of the 1A2 CWP motor that caused an unplanned reactor down power, the licensee failed to complete the interim corrective actions to use the installed resistance temperature detectors (RTDs) on the CWP motor stators to obtain temperatures for monitoring and managing any degrading trends to prevent another CWP overheating failure. Consequently fifteen months after the 1A2 CWP motor failure occurred, the 1A1 CWP motor experienced a similar failure and resulted in an unplanned reactor trip.

Description: On October 19, 2011 Unit 1 was operating at approximately 86 percent reactor power. The 1A2 CWP had been removed from service for planned maintenance on the condenser water box. The breaker for the CWP 1A1 unexpectedly tripped and resulted in a rapid loss of condenser vacuum. The reactor was manually tripped due to the impending loss of condenser vacuum. Emergency operating procedure EOP-1, Standard Post Trip Actions, and EOP-2, Reactor Trip Recovery, were completed and the unit was stabilized in mode 3. No equipment complications were identified. A failure evaluation of the 1A1 CWP motor found that the motor failed as a result of the stator windings overheating causing an electrical short on the winding. The overheating occurred due to the motor's cooling airflow passages being significantly blocked with corrosion products and salt deposits. This failure mechanism was the same as was experience on the 1A2 CWP motor that failed in July 2010.

For the July 2010 failure, long term corrective actions to prevent recurrence included requiring CWP motor air flow passage inspections and tests, and a motor rotor rebuild during routine overhauls. Short term corrective actions to prevent recurrence included performing periodic thermal monitoring of the CWP motors to identify any degrading air flow passage condition until rotors could be rebuilt during the overhaul periods. The licensee identified that using the installed RTDs to measure stator temperatures was the best method to monitor motor performance to ensure actions could be taken prior to a motor failure. Several corrective actions were assigned to take stator temperatures using the motor installed RTDs. These corrective actions included immediate temperature measurements on the remaining CWPs on Unit 1 and Unit 2, and quarterly temperature measurements on CWPs to identify any degrading trends.

The investigation of the October 2011 CWP motor failure identified that the corrective actions relating to recording and trending RTD stator temperatures had not been completed as assigned. The root cause identified that effective condition monitoring prior to the scheduled motor overhauls to detect degraded air flow passages was not performed. Several examples were provided describing that the corrective actions to take RTD stator temperatures had not been completed in a timely manner. For example, a corrective action to implement quarterly RTD temperature measurements for the motors did not provide sufficient detail to ensure this activity was completed in time to detect excessive temperatures on another CWP motor prior to failure. This action had not been initiated. The corrective action to revise the 4-KV motor preventive maintenance procedure to include recording RTD temperature measurements during a coupled run was closed to a procedure change request (PCR) prior to issuing the procedure for use. The licensee's CAP did not provide for a corrective action to be closed to a PCR. A corrective action to monitor motor stator temperatures using the installed RTDs had been closed even though the action had not been completed. A corrective action to revise a procedure to monitor the motor RTD temperatures was also closed to a PCR and was classified as an enhancement and had not been completed for over a year.

Analysis: The inspectors determined that the licensee's failure to implement timely corrective actions in accordance with CAP procedure PI-SL-205, Condition Evaluation and Corrective Action, to monitor and trend CWP motors stator temperatures using the installed RTDs was a performance deficiency. The performance deficiency was more than minor because it affected the equipment reliability attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using NRC Manual Chapter 0609.04, Significant Determination Process – Phase 1 screening, the finding was determined to be of very low safety significance (Green) because it was a transient initiator, but did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available.

Enforcement: No violation of NRC regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because the performance deficiency involved non-safety related equipment. The finding was determined to be of very low safety significance (Green) and was entered into the licensee's CAP as CR 1697977. The finding involved the cross-cutting area of Problem Identification and Resolution with a corrective action program aspect. Specifically, the licensee did not take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity. [P.1(d)]. This finding is identified as FIN 05000335/2012007-03, Failure to Implement Timely Corrective Actions Resulted in a Plant Trip.

b. Assessment of the Use of Operating Experience

(1) Inspection Scope

The team examined licensee's use of industry operating experience to assess the effectiveness of how external and internal operating experience information was used to prevent similar or recurring problems at the plant. In addition, the team selected operating experience documents (e.g., NRC generic communications, 10 CFR Part 21 reports, licensee event reports, vendor notifications, and plant internal operating experience items, etc.), which had been issued since March 2010 to verify whether the licensee had appropriately evaluated each notification for applicability to the St. Lucie site, and whether issues identified through these reviews were entered into the CAP. Documents reviewed are listed in the Attachment.

(2) Assessment

Based on a review of documentation related to the review of operating experience issues, the team determined that the licensee was generally effective in screening operating experience for applicability to the plant. Industry Operating Experience (OE) was screened by the corporate OE coordinator and relevant information was then forwarded to the site's OE coordinator. OE issues requiring action were entered into the CAP for tracking and closure. In addition, operating experience was included in all root cause evaluations in accordance with licensee procedure PSL-01.06.

The team identified several performance deficiencies associated with the licensee's operating experience program. These issues were screened in accordance with Manual Chapter 0612, "Issue Screening," and were determined to be of minor significance and not subject to enforcement action in accordance with the NRC's Enforcement Policy.

- The team identified two industry OE items that had not been evaluated by the site in the time specified by licensee's OE program. The licensee initiated CRs 1755951 and 1756043 to address these issues.
- The team identified one plant issue designated for external OE that was overdue by more than one year. The licensee initiated CR 1756043 to address this issue.

The team noted that one of the areas for improvement identified in PSL-11-035, Performance Improvement Audit, was associated with timeliness for some OE evaluations.

Documented below are two findings associated with information contained in vendor manuals that was not being effectively utilized in the operation and maintenance of plant equipment.

(3) <u>Findings</u>

i. <u>Failure to Implement Vendor Technical Manual Recommendations to Inspect EDG Immersion Heaters</u>

<u>Introduction:</u> A self-revealing apparent violation (AV) of Technical Specification 6.8.1.a was identified for failure to establish adequate maintenance procedures associated with the EDG system. Specifically, station personnel failed to establish preventative maintenance inspections of diesel immersion heaters in accordance with vendor manual recommendations. As a result, the Unit 1 1A EDG was immediately rendered inoperable for 43.5 hours due to a failed immersion heater that resulted in a leak of the 1A2 EDG jacket water system.

<u>Description:</u> On April 2, 2012 the licensee was conducting a routine surveillance run of the 1A EDG. Approximately 30 minutes into the surveillance run, the diesel tripped. During troubleshooting, the licensee determined that the diesel trip was due to a false high jacket water temperature condition. The jacket water temperature was not elevated to the point of actuating the trip. The licensee determined that the 1A2 diesel engine jacket water immersion heater had failed and was leaking jacket water at a rate of approximately 4 gallons per minute. The licensee removed the failed immersion heater and inspected for damage. The heater exhibited substantial corrosion. The failure of the heater caused a breach in the heater/jacket water boundary which allowed the jacket

water to leak onto the ground below the 1A2 diesel engine. The failure of the immersion heater concurrent with the jacket water leakage through the breached heater/jacket water boundary caused the diesel generator to become inoperable approximately 30 minutes after startup of the diesel.

The inspectors determined that the heater was installed in August, 2003. From August 2003, to the time of failure, the licensee routinely monitored jacket water chemistry and jacket water expansion tank level however no visual inspections of the immersion heater elements was conducted. The licensee had previously conducted a satisfactory 24 hour surveillance run on the 1A EDG on November 30, 2011. On March 11, 2012, the licensee observed jacket water color had changed from the normal pink color to an off-normal brown color. The licensee initiated CR 1743449 which identified this color change and stated that a previous 1B2 diesel engine immersion heater failure in 2003 also exhibited the coolant color change from pink to brown. As a result, the licensee initiated work order 401447789 to replace the 1A2 immersion heater. This work order was not performed prior to the catastrophic failure of the immersion heater on April 2, 2012.

Analysis: The failure to conduct visual inspections of EDG jacket water immersion heaters in accordance with the vendor manual and licensee procedure 00100431, Preventative Maintenance Program, is a performance deficiency and was within the licensee's ability to implement and prevent this issue. The immersion heater vendor manual provides guidance for conducting visual inspections of the heater elements. The failed immersion heater was installed in August, 2003 and since then no visual inspections were conducted nor was there a maintenance plan in place to ensure this maintenance activity was undertaken. The finding was considered more than minor because it impacted the Reactor Safety Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences and affected the cornerstone attribute of equipment performance. Specifically, the failed immersion heater resulted in a loss of jacket water and the inoperability of the EDG. As a result, the 1A EDG was declared inoperable for 43.5 hours while a new immersion heater was installed.

The inspectors evaluated the finding using IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process Phase 1 Operational Checklists for Both PWR's and BWR's." It was determined that a Phase II analysis was required to be completed by an NRC Senior Reactor Analyst (SRA) because the finding degraded the licensee's ability to cope with a loss of offsite power. The inspectors also evaluated the finding using IMC 0609, Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings," which required a Phase II analysis in accordance with IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." It was determined that a Phase III analysis was required to be completed because refinements to the Phase 2 analysis were required which incorporated exposure time and component failure probabilities in order to obtain a more realistic risk estimate.

The primary cause of the performance deficiency, as determined by the inspectors, was failure to implement vendor recommendations to periodically visually inspect immersion heaters. The inspectors determined that the cause of this finding was related to the Work Control component of the Human Performance cross-cutting area due to the failure to plan work activities to ensure long term equipment availability. [H.3(b)] Specifically, maintenance scheduling was more reactive than preventative.

Enforcement: The inspectors determined that the finding represents a violation of regulatory requirements because it involved improper implementation of procedures associated with safety-related plant equipment. Technical Specification 6.8.1.a requires that written procedures, specified in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, shall be established, implemented, and maintained. Regulatory Guide 1.33 states that maintenance activities that can affect the performance of safety-related equipment should be performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Chromalox vendor manual 161-306157-001, "Installation, Operations and Maintenance Instructions for Type TM-Series Industrial Flanged Immersion Heaters," states, in part, that users should "periodically remove the heater from the tank to inspect the elements for signs of corrosion and remove any deposits from the sheath." Contrary to the above, station personnel did not have maintenance procedures appropriate to the circumstances in that they failed to implement visual inspections of emergency diesel generator jacket water immersion heaters as described and recommended in the immersion heater vendor manual. As a result, the Unit 1 1A EDG was rendered inoperable for 43.5 hours on April 2, 2012 when the immersion heater failed causing a loss of jacket water from the 1A EDG. The issue was placed in the licensee's corrective action program as CR 1751214. This issue is being documented as AV 05000335/2012007-04, Failure to Implement Vendor Technical Manual Recommendations to Inspect EDG Immersion Heaters.

ii. Failure to Implement Vendor Described Preventive Maintenance on the Circulating Water Pump Motors

Introduction: A Green self-revealing finding was identified for the licensee's failure to implement vendor recommended preventive maintenance requirements to monitor and trend motor stator temperatures using the installed RTDs for the 1A2 CWP motor. Periodic monitoring of the 1A2 CWP stator temperatures using the installed RTDs could have shown degraded performance of the motor and the need for motor maintenance. As a result of not trending 1A2 CWP motor performance, the pump was allowed to run to failure causing an unplanned reactor power transient.

Description: On July 13, 2010 the Unit 1 control room operators received a ground alarm on the B auxiliary transformer. Immediately following the alarm, the 1A2 CWP breaker tripped open. A field operator reported that the 1A2 CWP motor was smoking and on fire. The plant fire brigade responded and extinguished the fire. Operators entered Abnormal Operating Procedure 1-AOP-22.01, Rapid Down Power, and reduced reactor power to 77 percent to prevent the unit from reaching the manual reactor trip set point due to decreased condenser vacuum. The licensee's root cause evaluation identified that the CWP maintenance overhauls did not address maintenance requirements for motors subject to heavy salt-laden environments. Licensee testing confirmed the CWP motor was shorted to ground. The motor's rotor was found to be heavily corroded with signs of swelling and metal separation. Indications of heavy salt deposits were seen throughout the rotor air passages. The licensee estimated that the salt deposits and corrosion caused the air passages to be approximately 80 percent blocked. The corrosion loosened and traveled to the end of the rotor and lodged within the airflow passages. Contributing causes included: not having adequate methods to detect degrading performance parameters on the pump motors, not having documented functional criteria for CWP motor stator temperatures comparison and acceptance, and the licensee's analysis and trending methods (thermography) did not reveal increasing CWP motor stator temperatures. CAPRs included a requirement to perform extensive motor air flow passage inspections and flow tests, and to perform motor rotor rebuilds during routine overhauls. Additional corrective actions included: performing thermal monitoring of the CWP motors to identify any degrading air flow passage condition until rotors were rebuilt, obtain and trend RTD stator temperature data on the remaining Unit 1 and Unit 2 CWP motors, and revising the preventive maintenance procedure 0-PME-100.02, Preventive Maintenance of Motors, to collect RTD stator temperatures on the motors. It was determined that monitoring stator temperatures using the installed RTDs would provide the most reliable data to identify motor degradation. The inspectors reviewed the General Maintenance section, under Protective Devices, of the GE vendor manual for this motor, GEK-33766, NY422208 Station Aux Motors. The manual described that RTDs were installed on the motor stators and recommended the RTDs be used as part of the preventive maintenance program on the motors. The inspectors verified that the RTDs came installed on the CWP motors and found that prior to this failure the licensee had not transposed the vendor manual RTD temperature measurement information to the station PM procedure 0-PME-100.02, Preventive Maintenance of Motors, to monitor thermal performance on the motor stators as described in the GE vendor maintenance manual.

Analysis: The failure to monitor CWP motor performance using the installed stator RTDs in accordance with vendor manual and licensee procedure 00100431, Preventative Maintenance Program, is a performance deficiency and was within the licensee's ability to foresee and correct. The performance deficiency was more than minor because it affected the equipment reliability attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using NRC IMC 0609.04, Significant Determination Process – Phase 1 screening, the finding was determined to be of very low safety significance (Green) because it was a transient initiator, but did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. The inspectors concluded that this finding did not have a cross-cutting aspect as this was not representative of present performance in that the CWP stator RTD temperatures had not been monitored since initial Unit 1 start up.

Enforcement: No violation of NRC regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because the performance deficiency involved non-safety related equipment. This finding was determined to be of very low safety significance (Green) and was entered into the licensee's CAP as CR

1758355. This finding is identified as FIN 05000335/2012007-05, Failure to Implement Vendor Described Preventive Maintenance on the Circulating Water Pump Motors.

c. Assessment of Self-Assessments and Audits

(1) Inspection Scope

The team reviewed audit reports and self-assessment reports, including those which focused on problem identification and resolution, to assess the thoroughness and self-criticism of the licensee's audits and self assessments, and to verify that problems identified through those activities were appropriately prioritized and entered into the CAP for resolution in accordance with licensee procedure PI-AA-101, Self-Assessment and Benchmarking Program.

(2) Assessment

The team determined that the scopes of assessments and audits were adequate. Self-assessments were generally detailed and critical, as evidenced by findings consistent with the inspector's independent review. The team verified that CRs were created to document all areas for improvement and findings resulting from the self-assessments, and verified that actions had been completed consistent with those recommendations. Generally, the licensee performed evaluations that were technically accurate.

The team reviewed Performance Improvement Audit PSL-11-035, dated December 30, 2011. The team determined that this audit was a critical review of the St. Lucie CAP, OE and Self-assessment programs. The audit findings were in line with the team's observations and findings contained in this report. The audit documented examples of items in the CAP not being corrected and closed in a complete, timely and accurate manner. The audit documented examples of corrective actions being closed to processes outside of the CAP and identified areas for improvement associated with timeliness for some OE evaluations. Findings contained in the Performance Improvement Audit had been entered in the CAP for resolution.

(3) Findings

No findings were identified.

d. Assessment of Safety-Conscious Work Environment

(1) Inspection Scope

During the course of the inspection, the team assessed the station's safety-conscious work environment (SCWE) through review of the stations Employee Concerns Program (ECP), discussions with the ECP Coordinator, interviews with various departmental personnel and the results from a 2010 Nuclear Safety Culture Survey. The team reviewed a sample of ECP issues to verify that concerns were being properly reviewed and identified deficiencies were being resolved and entered into the CAP when appropriate.

(2) Assessment

Based on the interviews conducted and the CRs reviewed, the team determined that licensee management emphasized the need for all employees to identify and report problems using the appropriate methods established within the administrative programs, including the CAP and ECP. These methods were readily accessible to all employees. Based on discussions conducted with a sample of plant employees from various departments, the team determined that employees felt free to raise issues, and that management encouraged employees to place issues into the CAP for resolution. The team did not identify any reluctance on the part of the licensee staff to report safety concerns. However, the number and content of anonymous ARs indicates that some plant personnel are reluctant to identify themselves.

(3) Findings

No findings were identified.

4OA3 Event Follow-up

.1 (Closed) Licensee Event Report (LER) 05000335/2011-003-00, 01, Long-Term Post LOCA Hot Leg Injection Single Failure Vulnerability

On November 3, 2001, with St. Lucie Unit 1 at 85 percent power, the Onsite Review Group determined that the past operation with unproceduralized manual actions to mitigate postulated single failures in the hot leg injection (HLI) flow path constituted a reportable condition. The licensee failed to recognize that the historical condition was reportable due to weaknesses in corrective action program implementation and legacy issues with operability/functionality determinations. The legacy design issue is being handled in the interim via proceduralized manual actions that are being tracked in as an operable but degraded condition. The inspectors reviewed the LER and CR 1692101 that documented the event. A licensee-identified violation is documented in section 4OA7 of this report. This LER is closed.

.2 (Closed) LER 05000335/2011-002-00 Unit 1 Manual Reactor Trip Due to High Condenser Backpressure

This LER documents a manual reactor trip that resulted from a loss of condenser vacuum due to a failed circulating water pump motor. The pump motor failed due to overheating of the motor windings. The licensee’s evaluation of this event identified that previous corrective actions, associated with taking stator temperatures using the resistance temperature devices, were not completed as assigned. Corrective actions included immediately taking motor stator temperatures on all the remaining Unit 1 and Unit 2 circulating pump motors and monitoring for thermal performance degradation. The inspectors reviewed the LER and CR 1697977 that documented the event. The inspectors identified one finding and it is documented in section 4OA2.a(3)(iii) of this report. This LER is closed.

4OA6 Meetings, Including Exit

On April 20, 2012, the inspectors presented the inspection results to Mr. R. Anderson and other members of the site staff. The inspectors confirmed that all proprietary information examined during the inspection had been returned to the licensee.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of the NRC Enforcement Policy for disposition as an NCV.

Title 10 of CFR Part 50, Appendix B Criterion XVI requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this, in 1999, the licensee documented (CR 99-1278) that the hot leg injection (HLI) methodology was not single failure proof, because a loss of an electrical bus would prevent both the primary and alternative HLI flow paths from being successful. The primary HLI injection flow path uses motor operated valves (MOVs), normally closed, fail-as-is, that are powered from train A and train B VAC buses. The alternate flow path uses solenoid operated valves that are powered by 125 VDC battery bus A and B. Valves in each HLI flow path are powered from the opposite train so that loss of electric power to train A or train B would render both flow paths inoperable. In 1999, the licensee determined that a HLI flow path could be restored by use of temporary jumpers to restore power to the MOVs affected by the loss of an electrical train. However, HLI procedures were not revised and were not fabricated at that time. In 2008, CR 2008-35069, documented that the previously identified jumpers and procedure changes were not 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 CRs still had not been implemented. Currently the licensee has fabricated the required jumpers and procedure changes have been implemented thus restoring compliance. 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 HLI, a required long term cooling safety function. The finding was evaluated in Phase 1 and determined to require a Phase 3 analysis due to the loss of system safety function. The condition was evaluated by a Regional SRA and determined to have very low safety significance (Green) based on the low likelihood of a large break LOCA and low likelihood of electrical failures requiring jumpers to be installed. This issue and corrective actions were documented in the licensee's corrective action program as Action Request (AR) 1703137.

ATTACHMENT: SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
R. Anderson, Site Vice President
C. Bach, Chemistry Manager
D. Cecchett, Licensing Engineer
J. DiVentura, ECP Coordinator
J. Fletcher, Maintenance Analyst
S. Gambill, Electrical System Engineer Supervisor
B. Hughes, Plant General Manager
E. Katzman, Licensing Manager
J. Kramer, Safety Manager
J. Owens, Performance Improvement Manager
R. Sciscente, Performance Improvement Analyst
M. Seidler, Security
G. Tullidge, PRA Analyst
T. Young, Security Manager

NRC personnel:
T. Hoeg, Senior Resident Inspector
G. Hopper, Chief, Branch 7, Division of Reactor Projects

LIST OF REPORT ITEMS

Opened

05000335/2012007-04	AV	Failure to Implement Vendor Technical Manual Recommendations to Inspect EDG Immersion Heaters (Section 4OA2.b(3)(i))

Opened and Closed

05000335/2012007-01	FIN	Failure to Perform Preventive Maintenance on the 1B Condensate Pump Discharge Check Valve (Section 4OA2.a(3)(i))
05000389/2012007-02	NCV	Failure to Correct a LPSI Pump Design Deficiency (Section 4OA2.a(3)(ii))
05000335/2012007-03	FIN	Failure to Implement Timely Corrective Actions Resulted in a Plant Trip (Section 4OA2.a(3)(iii))

05000335/2012007-05	FIN	Failure to Implement Vendor Described Preventive Maintenance on the Circulating Water Pump Motors (Section 4OA2.b(3)(ii))

Closed

05000335/2011-003-00, 01	LER	Long-Term Post LOCA Hot Leg Injection Single Failure Vulnerability (Section 4OA3.1)
05000335/2011-002-00	LER	Unit 1 Manual Reactor Trip Due to High Condenser Backpressure (Section 4OA3.2)

LIST OF DOCUMENTS REVIEWED

Procedures

PI-SL-204, Condition Identification and Screening Process, Revision 07
PI-SL-205, Condition Evaluation and Corrective Action, Revision 05
EN-AA-203-1001, Operability Determinations / Functionality Assessments, Revision 06
PI-AA-02, Self-Assessment, Revision 00
PI-AA-101-1001, Quick Hit Assessments, Revision 04
PI-AA-101-1002, Benchmarking Process, Revision 04
PI-AA-101, Self-Assessment and Benchmarking Program, Revision 09
PI-AA-102-1001, Operating Experience Program Screening and Responding to Incoming Operating Experience Guideline, Revision 08
ADM-07.04 Corrective Action Program Requirements, Revision 06
NAP-424 , Employee Concerns Program, Revision 02
NAP-203, Performance Improvement, Revision 07
EN-AA-203-1001, Operability Determinations/Functionality Assessments, Revision 06
ER-AA-201-2001, System and Program Health Reporting, Revision 04
OP-AA-108, Oversite and Control of Operator Burdens, Revision 00
1-AOP-14.01, Component Cooling Water Abnormal Procedure, Revision x
2-AOP-14.01, Component Cooling Water Abnormal Procedure, Revision x
NA-AA-200, Employee Concerns Program Process Description, Revision 05
IP-801, Evaluating and Reporting Defects and Failures to Comply for Substantial Safety Hazards in Accordance with 10CFR Part 21, Revision 16
NP-808, Evaluating and Reporting Defects and Failures to Comply for Substantial Safety Hazards in Accordance with 10 CFR Part 21, Revision 08
QI-16-QAD-6, 10 CFR Part 21 Tracking, Revision 18
0-AOP-117.02, Earthquake, Revision 03
1-NOP-04.04, Fuel Pool Cooling and Purification System – Normal Operation, Revision 02
2-NOP-04.04, Fuel Pool Cooling and Purification System – Normal Operation, Revision 02
PI-AA-102, Operating Experience Program, Revision 03
EN-AA-203-1001, Operability Determinations/Functionality Assessments, Revision 6.0
PI-AA-102-1001, Operating Experience Program Screening and Responding to Incoming Operating Experience Guideline, Version 8.0

PI-AA-101-1000-F01, PSL 2010 Mid Cycle Assessment
2-GOP-502, Data Sheets Required for Heating, Version 55
0-MMP-01.09, Pressurizer and Safety Valve Removal, Testing, and Installation, Version 12
0-NOP-99.06, Cold Weather Preparations, Revision. 0
0-NOP-100.01, Equipment Out of Service, Revision. 20
1-NOP-03.05, Shutdown Cooling, Revision. 44
1-OSP-100.27, Schedule of Periodic Tests, Checks and Calibrations, Revision. 0
FPL-1, Quality Assurance Topical Report, Revision. 11
OP-AA-102-1002, Seasonal Readiness, Revision. 0
OSP-73.01, Guidelines for the Implementation of the Snubber Inspection and Test Program, Revision. 12
SFI-2205, Fire Watch Patrols, Revision. 09
PSL-01.06, Root Cause Evaluation (RCE) Handbook, Revision 15
PSL-01.05, Apparent Cause Evaluation (ACE) Handbook, Revision 10
MA-AA-204, Preventative Maintenance and Surveillance Process, Revision 2
ER-AA-204, Preventative Maintenance Program Strategy, Revision 2
1-EOP-01, Standard Post Trip Actions, Rev. XX
1-EOP-02, Reactor Trip Recovery, Rev. XX

Condition reports (CRs)

115035	467552	532738	581588
161586	474791	561847	582828
161715	474904	561848	582988
166944	475021	565948	583822
1679935	475342	566450	583908
402593	475820	566679	584721
403638	476101	566897	585076
403640	476560	568366	589182
403654	476700	568399	589992
403656	476831	565918	590273
403680	476888	572328	591565
405295	476897	572807	592354
406085	476949	572977	592414
406355	476962	574203	594342
406374	476973	574322	594932
406461	477103	574844	596652
406522	477114	574864	596859
406574	477385	575519	597353
406583	479434	577132	598767
406631	479533	577608	1596002
406633	479545	578250	1598902
444126	479552	578252	1599962
454918	485295	579024	1602627
456678	485519	580587	1602763
463949	485553	580919	1604648
466819	532415	581586	1604740

1604749
1604801
1605505
1606391
1606397
1606401
1606759
1606844
1607017
1607055
1607368
1607487
1607519
1607813
1607894
1609089
1609204
1616671
1620394
1628804
1632513
1634859
1637942
1639211
1641552
1641675
1643190
1643270
1651817
1654920
1656030
1659235
1663248
1671013
1671865
1674516
1675666
1677136
1677155
1677190
1678839
1679127
1679462
1679896
1679935
1683622
1684794
1685597
1686303
1686625
1690940
1692101
1695066
1696007
1696577
1697977
1699200
1701203
1702003
1702023
1703137
1703690
1706204
1708811
1710695
1710700
1710883
1711279
1711280
1711777
1712847
1718398
1718584
1719681
1719735
1720124
1720320
1720816
1722728
1726908
1728702
1728975
1729908
1733108
1737527
1737601
1737764
1747947
1748747
1751066
1751182
1751466
1999-1278
2006-14726
2008-35069
2009-16124
2009-28830
2010-16326
2010-16789
1751214
1743449
1758355

Condition Reports written as a result of this inspection

1752272 Work order listed as a corrective action to prevent recurrence (CAPR) for CR 565948 to replace an auxiliary feedwater actuation system (AFAS) relay was inappropriately canceled.

1752303 CAPR closed to preventative maintenance change request (PMCR) and CR CAPR closed to PMCR and severity level 3 CR

1752842 Provide basis for allowing 7 days for fire protection equipment to be out of service before Engineering has to perform an evaluation and identification of any additional compensatory actions if required.

1755189 A condition report and subsequent evaluation was not generated or performed on the trip of the 1A Main Feedwater Pump when the 1B Condensate Pump was secured.

1755190 Post Trip Review and Caution Tag inappropriately noted required Operator actions. Required operator actions should have been proceduralized for the known check valve deficiency.

1755191 The 1B Condensate Discharge Check Valve was not tracked with an Operator Work Around when found to be stuck open after a Unit 1 Plant trip1755951 Untimely Review of NRC Information Notice (IN)11-12

1756043 Untimely operating experience (OE) submittal related to CR479533

1756069 Untimely Screening of External OE

1756212 Required reportability evaluation for those periods in which fuel pool purification was used to "clean-up" the refueling water tank (RWT). (NRC IN 2012-01, non-seismic piping connected to safety related tanks).

1756412 Deferral of condensate discharge check valve inspection preventative maintenance (PM) from “outage” based PMs to ‘online’ PMs in 2002 resulted in each of these valves being performed on a ten year frequency instead of on the recommended six year frequency.

Work Orders

400380038
39016634
4003718
40147789
40104889
40107114
40124375

Self-Assessments and Audits

PI-AA-101-1000-F01, PSL 2010 Mid Cycle Assessment
PSL-11-001, Security Audit
PSL-10-005, Security Audit
PSL-10-17, Corrective Maintenance
PSL-11-035, Performance Improvement Audit
PSL-10-043, Self Assessment Audit Report
PSL-10-022, Preventative Maintenance Audit Report

Other Documents

Cable Program Health Report, 1st Quarter 2012
MSP 09097
Unit 1 EDG System Health Report 1st Quarter 2012
Unit 2 EDG System Health Report 1st Quarter 2012
PSL IST Screening Report dated 4/4/12 0900
EDG Jacket Water Chemistry Trends 11/18/10 – 4/1/12
Unit 1 4.16kV System Health Report dated 1/1/12 – 3/31/12
Unit 2 4.16kV System Health Report dated 1/1/12 – 3/31/12
Unit 1 Auxiliary Feedwater Health Report dated 1/1/12 – 3/31/12
Unit 2 Auxiliary Feedwater Health Report dated 1/1/12 – 3/31/12
St. Lucie Nuclear Oversight Report PSL-11-035
Non Conformance Report NCR-382
Drawing 8770-G-879 HVAC – Control Diagrams – Sheet 2 Rev. 43
Drawing 8770-G-878 HVAC – Control Diagrams – Sheet 1 Rev. 36
ESBU-TB-96-03-RO, Westinghouse Technical Bulletin
CAR 06-074

List of Acronyms

ACE Apparent Cause Evaluation
AR Action Request
AV Apparent Violation
BWR Boiling Water Reactor
CAP Corrective Action Program
CAPR Corrective Action to Prevent Recurrence
CAR Design Modification
CDP Condensate Pump
CR Condition Report
CWP Circulating Water Pump
ECP Employee Concerns Program
EDG Emergency Diesel Generator
EOP Emergency Operating Procedure
ES Engineered Safeguards
FIN Finding
HLI Hot Leg Injection
HPSI High Pressure Safety Injection
HVAC Heating, Ventilation, and Air Conditioning
IMC Inspection Manual Chapter
IST Initial Screening Team
LER Licensee Event Report
LOCA Loss of coolant accident
LPSI Low Pressure Safety Injection
MCR Main Control Room
MFW Main Feedwater
MRC Management Review Committee
NCV Non-cited Violation
NI Nuclear Instrument
NRC Nuclear Regulatory Commission
OE Operating Experience
PCR Procedure Change Request
PM Preventive Maintenance
PMCR Preventive Maintenance Change Request
PWR Pressurized Water Reactor
RCE Root Cause Evaluation
RHR Residual Heat Removal
ROP Reactor Oversight Process
RTD Resistance Temperature Detector
RWT Refueling Water Tank
SCWE Safety-Conscious Work Environment
SDP Significance Determination Process
SRA Senior Reactor Analyst
TBD To be Determined
WO Work Order