



**UNITED STATES
NUCLEAR REGULATORY COMMISSION**
REGION IV
1600 E LAMAR BLVD
ARLINGTON, TX 76011-4511

August 26, 2014

Mr. Kevin Mulligan,
Site Vice President, Operations
Entergy Operations, Inc.
Grand Gulf Nuclear Station
P.O. Box 756
Port Gibson, MS 39150

**SUBJECT: GRAND GULF NUCLEAR STATION - NRC 95001 SUPPLEMENTAL
INSPECTION REPORT 05000416/2014009**

Dear Mr. Mulligan:

On June 20, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed a supplemental inspection at your Grand Gulf Nuclear Station. The enclosed report documents the results of this inspection, which were discussed with you and members of your staff, during an exit meeting on June 20, 2014, as well as during the re-exit meeting on August 6, 2014, with members of your staff.

As required by the NRC Reactor Oversight Process Action Matrix, this supplemental inspection was performed in accordance with Inspection Procedure 95001, "Supplemental Inspection for One or Two White Inputs in a Strategic Performance Area." The purpose of the inspection was to examine the causes for, and actions taken related to, a White Performance Indicator in the Initiating Events Cornerstone at Grand Gulf Nuclear Station. The performance indicator was for Unplanned Reactor Scrams per 7,000 Critical Hours and crossed the Green-to-White threshold during the first quarter of 2013. The performance indicator value was noted as 3.2.

By letter, dated May 13, 2013, the NRC informed you that because of the change in the performance indicator, the performance at your Grand Gulf Nuclear Station was in the Regulatory Response Column of the Reactor Oversight Process Action Matrix beginning in the first quarter of 2013. We also informed you of our intent to perform this supplemental inspection. The NRC staff was informed of your readiness for this inspection by your letter, dated February 28, 2014.

This supplemental inspection was conducted to provide assurance that: (1) the root causes and contributing causes of the events resulting in the White performance indicator, as well as the subsequent scram events, were understood; (2) to independently assess the extent of condition and extent of cause for each scram event; and (3) to provide assurance that the corrective actions for the risk-significant performance issues were sufficient to address the root causes and contributing causes to prevent recurrence of such scram events.

The NRC determined that the root and apparent cause evaluations completed for each of the individual unplanned reactor scrams that resulted in the White performance indicator, as well as the root cause evaluations completed for subsequent unplanned reactor scrams, were conducted to a level of detail commensurate with the significance of the problems and reached reasonable conclusions as to the root and contributing causes of the events. The NRC also concluded that you identified reasonable and appropriate corrective actions for each root and contributing cause and that the corrective actions appeared to be prioritized commensurate with the safety significance of the issues.

The Unplanned Scrams per 7,000 Critical Hours performance indicator returned below the Green-to-White threshold in the second quarter of 2013, but returned to White in the third quarter of 2013. The performance indicator value returned below the White threshold again in the fourth quarter of 2013 and currently remains in the Green range. Therefore, given your acceptable performance in addressing the White performance indicator that was the subject of this inspection, in accordance with the guidance in Inspection Manual Chapter 0305, "Operating Reactor Assessment Program," the White performance indicator will only be considered in assessing plant performance through the third quarter of 2013. As a result, the NRC determined the performance at Grand Gulf Nuclear Station to be in the Licensee Response Column of the ROP Action Matrix as of the date of this letter.

This inspection also reviewed the details of all five licensee event reports that were submitted to the NRC for unplanned scram events that occurred between the dates of December 29, 2012 and March 17, 2014. There was an additional unplanned scram event that occurred on March 29, 2014, but due to a vendor review in process, the root cause evaluation was not complete for this inspection period. Thus, the licensee event report for that event will not be addressed in this report.

Based on the results of this inspection, this report documents one NRC identified and one self-revealing finding of very low safety significance (Green). One of these findings was determined to involve a violation of NRC requirements and, thus, is considered a violation. However, because of the very low safety significance and because it was entered into your corrective action program, the NRC is treating this violation as non-cited, consistent with Section 2.3.2 of the NRC Enforcement Policy. If you contest the finding, the violation, or the significance of the non-cited violation, 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, D.C. 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 1600 E. Lamar Blvd, Arlington, Texas, 76011-4511; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Grand Gulf Nuclear Station.

In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region IV, and the NRC Resident Inspector at the Grand Gulf Nuclear Station. The information you provide will be considered in accordance with Inspection Manual Chapter 0305.

K. Mulligan

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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 component of 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/

Donald B. Allen, Chief
Project Branch C
Division of Reactor Projects

Docket No.: 50-416
License No.: NPF-29

Nonpublic Enclosure:
NRC Inspection Report 05000416/2014009
w/Attachment: Supplemental Information

cc w/enclosure:
Electronic Distribution for Grand Gulf Nuclear Station

K. Mulligan

- 3 -

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Letter and Inspection Report to Mr. Kevin Mulligan from Mr. Don Allen, dated August 26, 2014

SUBJECT: GRAND GULF NUCLEAR STATION - NRC 95001 SUPPLEMENTAL
INSPECTION REPORT 05000416/2014009

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket No.: 05000416
License No.: NPF-29
Report No.: 05000416/2014009
Licensee: Entergy Operations, Inc.
Facility: Grand Gulf Nuclear Station
Location: 7003 Baldhill Road
Port Gibson, MS 39150
Dates: June 16 - 20, 2014
Inspector: J. Drake, Senior Reactor Inspector
N. Greene, Ph.D., Health Physicist
L. Brandt, Reactor Inspector
M. Langelier, Project Engineer
Approved By: Donald B. Allen
Chief, Project Branch C
Division of Reactor Projects

Enclosure

SUMMARY

IR 05000416/2014009; 06/16/2014 – 06/20/2014; Grand Gulf Nuclear Station; Inspection Procedure 95001, "Supplemental Inspection for One or Two White Inputs in a Strategic Performance Area."

The inspection activities described in this report were performed between June 16 and June 20, 2014, by inspectors from the NRC's Region IV office. Two findings of very low safety significance (Green) are documented in this report. One of these involved a violation of NRC requirements. The significance of inspection findings is indicated by their color (Green, White, Yellow, or Red), which is determined using Inspection Manual Chapter 0609, "Significance Determination Process." Their cross-cutting aspects are determined using Inspection Manual Chapter 0310, "Aspects Within the Cross-Cutting Areas." Violations of NRC requirements are dispositioned in accordance with the NRC Enforcement Policy. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process."

Cornerstone: Initiating Events

- Green. The inspectors identified a Green finding resulting from the licensee's failure to follow Procedure EN-LI-102, "Corrective Action Process," Revision 23, and Procedure EN-OP-104, "Operability Determination Process," Revision 7, for an adverse condition. The licensee failed to repair degraded viewing ports on the isophase bus ducting in a timely manner. The licensee documented this issue in their corrective action program as Condition Report CR-GGN-2013-00319.

The failure to implement adequate corrective actions in a timely manner after the discovery and evaluation that the viewing windows on the isophase bus duct had the potential to cause a reactor scram is a performance deficiency. The performance deficiency was more than minor because it was associated with the Initiating Events cornerstone attribute of Human Performance and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations. Using Inspection Manual Chapter 0609, Appendix A, "Significance Determination Process (SDP) for Findings at Power," dated June 19, 2012, Exhibit 1, Section B, Transient Initiators, the inspectors determined that the issue has a very low safety significance (Green) because it only caused a reactor trip and did not cause a loss of mitigating equipment relied on to transition the plant from the onset of a trip to a stable shutdown condition. This finding has a cross-cutting aspect in the problem identification and resolution area, associated with operating experience, because the licensee failed to systematically and effectively collect, evaluate, and implement relevant internal and external operating experience in a timely manner [P.5]. (Section 4OA3.3)

- Green. The inspectors reviewed a self-revealing, Green, non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," resulting from the licensee's failure to prevent the repetition of a break of the first stage turbine sensing line, which resulted in a reactor scram. The licensee documented this issue in their corrective action program as Condition Report CR-GGN-2014-02824.

The failure to implement adequate corrective actions from the previous first stage turbine pressure sensing line break to preclude repetition of a significant condition adverse to quality was the performance deficiency. The performance deficiency was more than minor because it was associated with the Initiating Events cornerstone attribute of Human Performance and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations. Using Inspection Manual Chapter 0609, Appendix A, "Significance Determination Process (SDP) for Findings at Power," dated June 19, 2012, Exhibit 1, Section B, Transient Initiators, the inspectors determined that the issue required a detailed risk evaluation by the senior reactor analyst because the violation caused a reactor trip and the loss of mitigation equipment. The licensee performed an inadequate evaluation of the root cause of the 2012 steam sensing line break, resulting in inadequate corrective actions to prevent repetition. Therefore, this violation has a cross-cutting aspect in the problem identification and resolution performance area, associated with evaluation, because the licensee failed to thoroughly evaluate the issue to ensure that resolutions address causes and extent of conditions commensurate with their safety significance [P.2]. (Section 4OA3.5)

REPORT DETAILS

4. OTHER ACTIVITIES

4OA3 Follow-up of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) Licensee Event Report 05000416/2012-008-00: "Automatic Reactor Scram Due To A Main Turbine Generator Trip Initiated By The 'A' Phase Unit Differential Relay"

a. Inspection Scope

On December 29, 2012, at 12:18 a.m. Central Standard Time (CST), Grand Gulf Nuclear Station (GGNS) was in Mode 1 operating at 100 percent thermal power when an unexpected, automatic reactor scram occurred due to a main generator trip. The licensee noted that all systems responded as expected with the exception of safety relief valve 1B21F047A, which was slow to close automatically; and high pressure (HP) feedwater heater start-up outlet valve 1N21F010B, which did not open automatically when the start-up level control valve was placed in service. Safety relief valves opened at the onset of the event to control reactor pressure, as designed. The inspectors responded to the site and verified the plant systems responded as designed, and that the operators stabilized the plant in accordance with station procedures.

Site personnel determined the scram was caused by a trip of the 'A' phase unit differential relay, which caused the generator lockouts to trip and ultimately resulted in a turbine trip and reactor scram. The licensee determined that the potential causes of the 'A' phase unit differential relay trip were either a spurious actuation of the differential relay, a fault in the current transformer (CT) relay circuitry, or an internal fault of a current transformer. Because the licensee's testing and inspection activities did not identify a definite failure mode, the licensee determined that an intermittent failure of the 'A' phase unit differential relay was the most-likely cause of the relay trip.

As corrective action, the licensee replaced the unit differential relays for all three phases (A, B, and C) and returned the plant to online operations on January 1, 2013. The licensee installed monitoring equipment prior to restart and the monitoring equipment did not detect a phase-differential fault while the licensee brought the generator online. Documents reviewed as part of this inspection are listed in the attachment. One finding and one non-cited violation (NCV) related to this event are documented in Section 4OA3 of Inspection Report 05000416/2013002. This LER is closed. This event follow-up review constituted one sample as defined in Inspection Procedure 71153.

b. Findings

No findings were identified.

.2 (Closed) Licensee Event Report 05000416/2013-001-00: “Automatic Reactor Scram Due To A Main Turbine Generator Trip Initiated By The ‘A’ Phase Unit Differential Relay”

a. Inspection Scope

On January 4, 2013, at 11:37 p.m. CST, Grand Gulf Nuclear Station was in Mode 1, operating at 94 percent rated thermal power during power ascension when the reactor automatically scrammed due to an ‘A’ phase unit differential signal, resulting in a main generator/turbine trip and subsequent reactor scram. The NRC inspectors responded to the site and verified the plant systems responded as designed and that the operators stabilized the plant in accordance with station procedures.

The licensee determined a ground condition had occurred on the ‘A’ phase of the generator neutral current transformer. The ground condition was caused by inadequate spacing between the current transformer and support bolts. During power operations, thermal expansion and relative vibration allowed the support bolts to make contact with the current transformer and damaged the insulation causing a ground condition. This resulted in a main generator trip and subsequent plant scram. The licensee took corrective action to remove the damaged current transformer and corrected other identified bolting issues prior to startup.

This was a repeat occurrence from the documented December 29, 2012, scram event. Once the licensee determined the apparent cause of the scram and implemented corrective actions, the licensee commenced startup activities on January 8, 2013. The licensee reached 100 percent rated thermal power on January 11, 2013. Documents reviewed as part of this inspection are listed in the attachment. One finding related to this event is documented in Section 4OA3 of Inspection Report 05000416/2013002. This LER is closed. This event follow-up review constituted one sample as defined in Inspection Procedure 71153.

b. Findings

No findings were identified.

.3 (Closed) Licensee Event Report 05000416/2013-002-00: “Automatic Reactor Scram Due To A Main Turbine Generator Trip Initiated By A Main Generator Neutral Ground Relay Trip”

a. Inspection Scope

On January 14, 2013, at 6:05 p.m. CST, Grand Gulf Nuclear Station was in Mode 1 operating at 100 percent rated thermal power when the plant experienced an automatic reactor scram. The scram was due to a neutral time overcurrent relay tripping, which caused a generator lockout to trip, resulting in a turbine trip and subsequent reactor scram because the reactor was greater than 30 percent power. The NRC inspectors responded to the site and verified the plant systems responded as designed, and that the operators stabilized the plant in accordance with station procedures.

The licensee determined that the ground that was detected on the bus was caused by water intruding into the isophase bus duct through a degraded viewing port on top of the isophase bus duct and accumulating in the vertical sections of the duct. The accumulated water collected on a seal-off bushing, which serves as a barrier in the bus ducts to re-direct air flow to the spare transformer. The collection of water on the seal-off bushings grounded the main conductor to the duct wall, tripping the neutral time overcurrent relay, and resulted in a turbine generator trip.

The licensee took corrective measures to stop the water intrusion into the isophase bus duct and to electrically isolate the spare transformer from the energized transformers prior to startup. The licensee commenced startup activities on January 27, 2013, and achieved 100 percent rated thermal power on February 6, 2013. Documents reviewed as part of this inspection are listed in the attachment. One finding and one NCV related to this event are documented in Section 4OA3 of Inspection Report 05000416/2013002. One additional finding is documented in this inspection report. This LER is closed. This event follow-up review constituted one sample as defined in IP 71153.

b. Findings

.1 Failure To Correct Degraded Viewing Ports In A Timely Manner

Introduction. The inspectors identified a Green finding resulting from the licensee's failure to follow procedures EN-LI-102, "Corrective Action Process," Revision 23, and Procedure EN-OP-104, "Operability Determination Process," Revision 7, for an adverse condition. The licensee failed to repair degraded viewing ports on the isophase bus ducting in a timely manner. It was identified in 2002 that degraded viewing ports on the isophase ducting could allow water infiltration which could cause a turbine trip. The licensee failed to repair the viewing ports which allowed water to leak into the isophase bus ducting causing a ground resulting in a turbine trip and subsequent reactor scram.

Description. On January 14, 2013, at 6:05 p.m. with the unit in Mode 1 operating at 100 percent rated thermal power, an unexpected turbine trip due to a main generator lockout followed by an automatic reactor scram occurred. Safety relief valves opened at the onset of the event to control reactor pressure and reseated properly. The operators entered the appropriate off-normal event procedures and the plant was stabilized with pressure control on the main turbine bypass valves and level control on the start-up level control valve.

The cause of the reactor scram was determined to be the main generator isolated phase bus cooling system experienced partial grounding due to design configuration of the horizontal bushing in an energized section of the bus, in close proximity to a degraded viewing port, which allowed water accumulation that created a ground condition.

Condition Report CR-GGN-2002-01858 issued on September 20, 2002, identified a degraded viewing port on top of the isophase bus duct (IPBD) that could allow water infiltration into the bus ducting. An engineering request was issued requesting a design to correct the degraded condition. In lieu of an engineering design, a vendor manual addendum (VMA 02/0105) for the isophase bus duct vendor manual (VM 460000352)

was created that stated the viewing window ports are prone to failure from degradation or hail damage and could result in water infiltration into the isophase bus duct, creating a ground and causing a turbine trip and subsequent reactor scram. The licensee identified some of the degraded viewing window ports and covered them with a solid cover as part of the corrective actions for the condition report. However, there were additional degraded viewing ports that should have been addressed. No further corrective actions occurred on this condition report. Thus, the inspectors determined that because there was a potential for the degraded or damaged viewing ports to cause a reactor scram and the fact that water infiltration from the degraded viewing ports actually contributed to the cause of the reactor scram on January 14, 2013, as identified by the licensee, that this was a condition adverse to quality that the licensee failed to correct in a timely manner resulting in the event.

Procedure EN-LI-102, "Corrective Action Process," Revision 23, defined degraded condition as a condition in which the qualification of a structure, system, or component or its functional capability is reduced. Examples of degraded conditions are failures, malfunctions, deficiencies, deviations, and defective material and equipment. Examples of conditions that can reduce the capability of a system are aging, erosion, corrosion, improper operation, and maintenance.

Section 5.9, Item (c), required, in part, "Any Operable-DNC or Operable-Comp Measures conditions not resolved prior to the completion of the next outage of sufficient duration shall be evaluated for continued operability into the next cycle of operation. This evaluation is reviewed and approved by the Onsite Safety Review Committee (OSRC) prior to startup from the outage [Gentletr9118R1], [INS9620004]."

In addition, Section 5.9, Step 4, Item (e), stated, in part, "The specific restriction preventing the timely completion of the item, resulting in the need to use the Long Term CA classification, must be documented in the CA or as otherwise referenced in the CA. Long Term CA classifications are normally assigned at time of CA initiation (vice changing to Long Term at the due date)."

Procedure EN-OP-104, "Operability Determination Process," Section 5.11, Step 4, "Timeliness of Corrective Action," Item (a), stated, in part, "A schedule must be established to resolve each OPERABLE but Degraded or Nonconforming Condition." Item (g) stated, "Restoration of Degraded components to meet the ASME code or Construction Code acceptance standards is expected to be completed by the end of the next refueling outage by the NRC." In addition, Item (h) stated, "If the plant does not resolve the Degraded or Nonconforming Condition at the first available opportunity or does not appropriately justify a longer completion schedule, the regulator would conclude that corrective action has not been timely and would consider taking enforcement action."

Contrary to the above expectations, the licensee failed to correct the degraded viewing ports in a timely manner and water infiltration to the isophase bus ducting resulted in a reactor scram. The licensee documented the January 14, 2013, scram event in their corrective action program as Condition Report CR-GGN-2013-00319. The licensee took corrective actions to reenergize portions of the isophase bus associated with the spare

transformer and install covers over the isophase bus duct viewing ports to correct the condition that caused the event.

Analysis. The failure to implement adequate corrective actions in a timely manner after the discovery and evaluation that the viewing windows on the isophase bus duct had the potential to cause a reactor scram is a performance deficiency. The performance deficiency was more than minor because it was associated with the initiating events cornerstone attribute of human performance and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations. Using Inspection Manual Chapter 0609, Appendix A, "Significance Determination Process (SDP) for Findings at Power," dated June 19, 2012, Exhibit 1, Section B, Transient Initiators, the inspectors determined that the issue has a very low safety significance (Green) because it only caused a reactor trip and did not cause a loss of mitigating equipment relied on to transition the plant from the onset of a trip to a stable shutdown condition.

Even though the licensee failed to adequately address the original condition report in 2002, they had opportunity to use this operational experience (either from the condition report or VMA) recently during the design of the modifications to the isophase bus duct. Therefore, this finding has a cross-cutting aspect in the problem identification and resolution area, associated with operating experience, because the licensee failed to systematically and effectively collect, evaluate, and implement relevant internal and external operating experience in a timely manner [P.5].

Enforcement. Procedure EN-OP-104, "Operability Determination Process," Revision 7, Section 5.11, step 4, "Timeliness Of Corrective Action," Item a, stated, in part, "A schedule must be established to resolve each OPERABLE but Degraded or Nonconforming Condition."

Item (g) stated, in part, "Restoration of Degraded components to meet the ASME code or Construction Code acceptance standards is expected to be completed by the end of the next refueling outage by the NRC."

Item (h) stated "if the plant does not resolve the Degraded or Nonconforming Condition at the first available opportunity or does not appropriately justify a longer completion schedule, the regulator would conclude that corrective action has not been timely and would consider taking enforcement action." Contrary to this, action taken by the licensee for a condition adverse to quality was not completed by the end of the next refueling outage. Specifically, the corrective actions taken for degraded viewing windows on the isophase bus duct in 2002 were inadequate and untimely, allowing water infiltration into the isophase bus duct causing a ground resulting in a turbine trip and subsequent reactor scram. This finding was of very low safety significance and was entered into the licensee's corrective action program as Condition Report CR-GGN-2013-00319; FIN 05000416/2014009-01, "Failure To Correct Degraded Viewing Ports In A Timely Manner."

.4 (Closed) Licensee Event Report 05000416/2013-003-00: "Unanticipated Reduction In Load Demand And Subsequent Main Turbine Control Valve Closure Resulting In An Unplanned Reactor Scram From A Reactor Pressure Transient"

a. Inspection Scope

On July 30, 2013, at 2:32 p.m. CST, GGNS was in Mode 1 operating at 100 percent rated thermal power when it experienced an unexpected reactor scram due to a high reactor pressure signal detected by the reactor protection system (RPS). Reactor core isolation cooling (RCIC) initiated and briefly injected during the transient. The licensee noted that all other systems responded as expected and no safety relief valves actuated. The NRC inspectors responded to the control room and verified that the plant systems responded as designed and that the operators stabilized the plant in accordance with station procedures.

The direct cause of the scram was due to a failure of the 'B' turbine stress evaluator (TSE) transmitter, which caused turbine load demand to decrease, which then caused the turbine control valves to close and the bypass valves to open. When the bypass valves reached maximum capacity and the turbine control valves continued to close, reactor pressure increased, and the reactor scrammed on high reactor pressure of 1065 psig.

Human performance issues led to this scram event when the licensee failed to properly troubleshoot the TSE and correctly identify the failed temperature transmitter. The licensee took corrective actions for the scram by replacing the failed TSE transmitter and put corrective actions in place prior to startup. Documents reviewed as part of this inspection are listed in the attachment. One finding related to this event is documented in Section 4OA3 of Inspection Report 05000416/2013004. This LER is closed. This event follow-up review constituted one sample as defined in Inspection Procedure 71153.

b. Findings

No findings were identified.

.5 (Closed) Licensee Event Report 05000416/2014-002-00: "Manual Actuation of the Reactor Protection System due to Steam Leak with Reactor Core Isolation Cooling Manual Initiation"

a. Inspection Scope

On March 17, 2014, at 5:14 a.m. CST, GGNS was in Mode 1 operating at 41 percent power during the power ascension from refueling outage 19 when the RPS was manually actuated to shut down the reactor due to a steam leak in the turbine building. The cause of the event was a steam leak in the turbine building resulting from a failed turbine first stage pressure sensing line, followed by failure of a four inch drain line for the main steam line. The 'B' failed turbine first stage pressure sensing line was attached

to the side of the main steam drain line via welds. The drain line allows water and moisture to be removed from the main steam lines and transferred to the condenser to prevent turbine damage. The failure of the 'B' turbine first stage pressure sensing line increased the stresses on the main steam line drain line causing it to fail, which resulted in a steam leak. The steam leak resulted in a manual actuation of the RPS to shut down the reactor.

After the scram, reactor core isolation cooling was manually started. Manual cycling of the safety relief valves and reactor core isolation cooling was used to maintain reactor water level and pressure. The appropriate off-normal event procedures were entered to mitigate the transient with all systems responding as designed. All control rods inserted to shut down the reactor. The NRC inspectors responded to the control room and verified that the plant systems responded as designed and that the operators stabilized the plant in accordance with station procedures.

The licensee implemented corrective actions, which included reactor water level and pressure to be maintained, so that the plant may be placed in a stable condition. The licensee replaced the failed drain line and removed both failed turbine first stage pressure sensing lines. Other contributing causes were evaluated and corrective actions were developed to address these process issues. Documents reviewed as part of this inspection are listed in the attachment. One NCV related to this event is documented in Section 4OA3 of Inspection Report 05000416/2014003. One additional NCV is documented in this inspection report. This LER is closed. This event follow-up review constituted one sample as defined in Inspection Procedure 71153.

b. Findings

.1 Failure to Correct a Significant Condition Adverse to Quality and Preclude Repetition

Introduction. The inspectors reviewed a self-revealing, Green, non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," resulting from the licensee's failure to prevent the repetition of a break of the first stage turbine sensing line, which resulted in a reactor scram.

Description. On March 17, 2014, at 5:14 a.m. CST, with the unit in Mode 1 operating at approximately 41 percent rated thermal power during power ascension from refueling outage 19, operators inserted a manual reactor scram due to a steam leak in the turbine building. The main steam isolation valves (MSIVs) were manually shut and the reactor core isolation cooling system was manually initiated. No safety relief valves actuated automatically. Manual cycling of safety relief valves and reactor core isolation cooling were used to maintain reactor water level and pressure within normal bands. The appropriate off-normal event procedures were entered to mitigate the transient with all systems responding as designed.

The licensee entered cold shutdown and initiated an investigation into the steam line break. They determined that a modification that was done during the refueling outage to attach the three-quarter inch first stage sensing lines to the four inch drain line had failed at the welded attachment. The most likely cause of sensing line and then the four inch

drain line failures was high amplitude, low cycle fatigue resulting in the 'B' sensing line separation occurring at 3:31 a.m. CST on March 17, 2014. This produced force imbalances and oscillations from the steam escape that adversely affected the four inch drain line to the point of its failure at 5:14 a.m. CST on March 17, 2014.

On June 16, 2012, a similar failure of the main steam 'A' first stage HP turbine pressure sensing line occurred resulting in the inoperability of the first stage pressure transmitters required to be operable at or above the low power setpoint per Technical Specifications 3.3.1.1, 3.3.4.1, and 3.3.2.1. The licensee characterized this failure as a significant condition adverse to quality due to the potential of a future occurrence causing a challenge to nuclear safety (i.e., plant transient). Two corrective actions to preclude repetition were implemented based on the root cause evaluation conducted at the time. The corrective actions to preclude repetition implemented in 2012 were not adequate to preclude repetition of a first stage turbine pressure sensing line break as evident by the March 17, 2014 event.

The licensee documented the March 17, 2014, event in their corrective action program as Condition Report CR-GGN-2014-02824. The licensee took immediate corrective actions to repair the broken four inch drain line. The licensee elected not to reinstall the sensing lines to the drain lines prior to startup and instead chose to use a temporary modification to achieve the same function of the sensing lines. The licensee performed a root cause evaluation and they have evaluated the programmatic elements of this event.

Analysis. The failure to implement adequate corrective actions from the previous first stage turbine pressure sensing line break to preclude repetition of a significant condition adverse to quality was the performance deficiency. The performance deficiency was more than minor because it was associated with the Initiating Events cornerstone attribute of Human Performance and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations. Using Inspection Manual Chapter 0609, Appendix A, "Significance Determination Process (SDP) for Findings at Power," dated June 19, 2012, Exhibit 1, Section B, Transient Initiators, the inspectors determined that the issue required a detailed risk evaluation by the senior reactor analyst because the violation caused a reactor trip and the loss of mitigation equipment.

Conditional Core Damage Probability: The analyst evaluated the increased risk from the performance deficiency using the Standardized Plant Analysis Risk Model for Grand Gulf Station, Version 8.22. The conditional core damage probability for a loss of main feedwater with secondary steam valves remaining closed was 8.62×10^{-7} . The dominant sequences were 71, 31, and 55, making up approximately 96 percent of the risk.

- Sequence 71 was a failure of the main condenser, HPCS, RCIC and the failure to depressurize.

- Sequence 31 was a failure of the main condenser, HPCS, suppression pool cooling, shutdown cooling, containment spray, late recovery of the power conversion system, and containment venting.
- Finally, Sequence 55 was a failure of the main condenser, HPCS, RCIC, late suppression pool cooling, shutdown cooling, containment spray, late recovery of the power conversion system, and containment venting.

To support the evaluation, the analyst assumed that there was sufficient inventory remaining in the main condenser to provide condensate to the reactor and that all containment cooling systems and safety-relief valves were operable at the time of the event. These assumptions were confirmed via inspection. Given a conditional core damage probability of 8.62×10^{-7} and the associated guidance in the Risk Assessment of Operational Events Handbook, Volume 1, "Internal Events," Revision 2, this is a finding of very low safety significance.

External Events: Manual Chapter 0609, Appendix A, Section 6.0 requires, "when the internal events detailed risk evaluation results are greater than or equal to $1.0E-7$, the finding should be evaluated for external event risk contribution." The analyst noted that this detailed risk assessment evaluates an actual event in which no external events occurred. Additionally, the analyst determined that the only external event that could have caused the failure of the steam lines was a seismic event. However, a seismic event of sufficient energy to cause a failure of the line would also cause a non-recoverable loss of offsite power. Following such an event, secondary equipment would not be available. Therefore, the change in core damage frequency would be negligible. Based on this review, the analyst concluded that the risk from external events, given the subject performance deficiency was essentially zero.

Conditional Large Early Release Probability: In accordance with the guidance in NRC Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," the analyst performed a screening analysis. The analyst divided the 65 core damage sequences provided in the internal events evaluation into the following 4 groups:

1. Core damage occurs while reactor pressure is high;
2. Core damage occurs while reactor pressure is low;
3. Reactor pressure at the time of core damage is unknown; and
4. Core damage occurs following an anticipated transient without scram.

For core damage sequences that occur when the reactor coolant system is at high pressures, Appendix H provides a screening value of 0.2 for the probability of containment failure upon vessel breach. As a conservative measure, the analyst applied this screening value to all sequences in Groups 1, 3, and 4. As documented in Appendix H, the screening value for core damage sequences that occur when the reactor coolant system is at low pressures is 0.0. The resulting conditional large early release probability was 8.39×10^{-8} .

Results: Based on the results of the conditional core damage probability with the addition of the external events contributors and the conditional large early release probability, the analyst concluded that the finding was of very low safety significance (Green).

The licensee performed an inadequate evaluation of the root cause of the 2012 steam sensing line break resulting in inadequate corrective actions to prevent repetition. Therefore, this violation has a cross-cutting aspect in the problem identification and resolution performance area, associated with evaluation, because the licensee failed to thoroughly evaluate the issue to ensure that resolutions address causes and extent of conditions commensurate with their safety significance [P.2].

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that in the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and action taken will preclude repetition. Contrary to this, action taken by the licensee for a significant condition adverse to quality did not preclude repetition. Specifically, the corrective actions taken for a line break of the first stage turbine pressure sensing line in June 2012 were not adequate to preclude repetition of a similar line break of the first stage pressure sensing line in March 2014 resulting in an unplanned reactor scram.

Because this violation was of very low safety significance and was entered into the licensee's corrective action program as Condition Report CR-GGN-2014-02824, this violation is being treated as a non-cited violation, consistent with Section 2.3.2.a of the Enforcement Policy; NCV 05000416/2014009-02, "Failure To Correct A Significant Condition Adverse To Quality And Preclude Repetition."

Conclusively, all of these activities reviewed constitute completion of five event follow-up samples, as defined in Inspection Procedure 71153.

40A4 Supplemental Inspection (95001)

.1 Inspection Scope

This inspection was conducted in accordance with Inspection Procedure 95001, "Supplemental Inspection for One or Two White Inputs in a Strategic Performance Area," to assess the licensee's evaluation of one White performance indicator in the reactor safety initiating events cornerstone. The performance indicator was for unplanned reactor scrams per 7,000 critical hours and it exceeded the Green-to-White threshold as reported in the licensee's first quarter 2013 performance indicator submittal.

The inspection objectives were to:

- 1) Provide assurance that the root causes and contributing causes of risk-significant performance issues are understood
- 2) Provide assurance that the extent of condition and extent of cause of risk-significant performance issues are identified

- 3) Provide assurance that the licensee's corrective actions for risk-significant performance issues are sufficient to address the root and contributing causes and to prevent recurrence

The three unplanned reactor scrams (LER 2012-008-00, LER-2013-001-00, and LER 2013-002-00) that caused the performance indicator to exceed the Green-to-White threshold, as well as the two subsequent scram events (LER 2013-003-00 and LER 2014-002-00) are all described above in Section 4OA3.

By letter, dated February 28, 2014, the licensee notified the NRC that applicable corrective actions to address the White performance indicator had either been planned, initiated, or completed, and that it was ready for the NRC to conduct this supplemental inspection to review the actions taken to address it. In preparation for the 95001 inspection, the licensee performed root cause and/or apparent cause evaluations for each scram event, as well as completed a Snapshot Assessment Report entitled, "Pre-NRC 95001 Inspection Snapshot Assessment," dated January 16, 2014. These documents were the primary documentation reviewed during the inspection to address the specific requirements of the 95001 inspection procedure.

In addition to the evaluations performed for the White performance indicator mentioned above, NRC inspectors also reviewed the licensee event reports, relative condition reports, root cause evaluation procedures, operating procedures, plant parameters, alarm response instructions, corrective action procedures, applicable engineering changes, and any relative violations and/or findings issued.

The inspectors reviewed corrective actions to ensure that they adequately addressed the identified causes. The inspectors also held discussions with licensee personnel to ensure that the root and contributing causes, as well as the contribution of safety culture components, were understood, and that corrective actions planned and/or implemented were appropriate to address the documented causes and preclude repetition of such an event.

The following inspection results are organized by the specific inspection requirements of Inspection Procedure 95001, which are noted in italics per each section.

.2 Evaluation of Inspection Requirements

It is noteworthy to state that the inspection requirements addressed below are based on the cohesive unit of events. In other words, our *overall* assessments will be described for each requirement, versus discussion of individual assessments for each event. However, observations made for review of the individual scram events will be discussed briefly as needed, but any determination made relative to an inspection requirement is based on the causal evaluations, corrective actions, and safety culture components cohesively.

2.01 Problem Identification

- a. *Determine whether the evaluation identified who (i.e., licensee, self-revealing, or NRC), and under what conditions the issue was identified.*

An event narrative was presented for each reactor scram reviewed that discussed the conditions under which the scram was identified. Each of the unplanned scrams described above that contributed to the White performance indicator, as well as each subsequent scram, was the result of self-revealed events. The licensee and NRC inspectors both correctly recognized the White performance indicator after the second reactor scram occurred in 2013, resulting in an indicator value of 3.2, exceeding the threshold value of 3. NRC inspectors determined that the licensee's snapshot assessment adequately identified when the Unplanned Reactor Scrams per 7,000 Critical Hours performance indicator crossed the Green-to-White threshold; although, they discussed and evaluated some scram events from as early as the year 2008.

- b. *Determine whether the evaluation documented how long the issue existed and whether there were any prior opportunities for identification.*

The Unplanned Reactor Scrams per 7,000 Critical Hours performance indicator exceeded the Green-to-White threshold as reported in the licensee's first quarter 2013 performance indicator submittal. The licensee's evaluation correctly documented that this occurred with the third unplanned reactor scram on January 14, 2013.

As discussed in the licensee's evaluation for scram events that occurred on December 29, 2012, and on January 4, 2013, each of the three reactor scrams was sufficiently unique, such that there was no prior opportunity for identification and actions to preclude the performance indicator exceeding the White threshold. In fact, the initial two scram events discussed were only separated by several days.

- c. *Determine whether the licensee's root cause evaluation documented the plant specific risk consequences and compliance concerns associated with the issue.*

As noted in the licensee's evaluation, the White performance indicator represents performance outside an accepted range of nominal utility performance, thus indicating an increase in the frequency of those events with the potential to interfere with plant stability and challenge critical safety functions during power operation. The inspectors determined that nuclear safety significance and risk was appropriately discussed in the licensee's evaluation for the White performance indicator and also adequately evaluated by the licensee in the separate root or apparent cause evaluations performed for each of the five unplanned reactor scram events that were reviewed.

In response to each of the unplanned reactor scrams, the NRC inspectors evaluated plant parameters, operator actions, and overall plant status by reviewing the post-trip analysis, including the availability of mitigating systems. For each of the scrams, the inspectors determined that all required safety systems responded as designed; the

scrams were not complicated by material condition deficiencies. Inspectors also determined that no human performance errors complicated the event response.

Relative to compliance concerns associated with each event, the licensee did address the possible findings that may be attributed to the issues. However, the licensee failed to particularly identify that the failure to correct the viewing ports on the isophase bus duct was the primary performance deficiency leading to a reactor scram as documented as a finding in Section 4OA3.3; thus, this finding was characterized as NRC-identified. The other self-revealing non-cited violation, as documented in Section 4OA3.5, was discussed in-depth in the documentation reviewed by the inspectors.

d. Findings

No findings were identified.

2.02 Root Cause, Extent of condition, and Extent of cause Evaluation

a. *Determine whether the licensee's root cause evaluation applied systematic methods in evaluating the issue in order to identify root causes and contributing causes.*

The inspectors determined that the primary root cause evaluations adequately applied systematic methods in evaluating the issue. In its root cause analyses, the licensee used Event and Causal Factors Charts, Fault Trees, Failure Mode Analysis (FMA), Why Staircase Trees, Hazard-Barrier-Target Analysis, Stream Analysis, and comparative timelines.

b. *Determine whether the licensee's root cause evaluation was conducted to a level of detail commensurate with the significance of the problem.*

Overall, the inspectors determined that the primary root cause evaluations performed were conducted to a level of detail commensurate with the significance of the problem discussed. However, this is based on a cohesive review of root cause evaluations performed for all five scram events discussed above.

Observation

As the inspectors reviewed the current transformer scram events (from December 29, 2012, and January 4, 2013) and the isophase bus scram event (from January 14, 2013), it was evident that the causal evaluations were not robust or sufficiently detailed and probing to identify the root and contributing causes to the events. Specifically, the initial causal evaluation performed for the current transformer scram event was not conducted to the level of detail commensurate with the significance of the problem. In fact, only an apparent cause evaluation was performed for the December 29, 2012, scram event. However, this was upgraded to a root cause evaluation during the second current transformer scram event on January 4, 2013. Both current transformer scram events were consolidated into one root cause evaluation.

In the root cause evaluation performed for the current transformer scram events, the licensee failed to identify any contributing causes, even though in the narrative of the root cause evaluation, several items were discussed that contributed to the event. However, those items were not characterized as contributing causes in the final analysis of the root cause evaluation. In addition, it seems as though the licensee missed identifying the primary root cause in the current transformer events. After reviewing the root cause evaluation and having discussion with the licensee, the inspectors determined that a *lack of resources* was most likely the root cause of the unplanned scram, or at least a major contributing cause. Similarly, in the isophase bus duct event, the licensee determined the root cause to be *design configuration*. The inspectors did not agree with this determination. They felt design configuration was better characterized as the apparent cause.

The licensee understood the concerns presented by the inspectors and placed the issues into their corrective action program for further review. However, the licensee was able to show improving performance in their evaluations. The inspectors ultimately determined that in the wide scheme of events, the licensee understood the level of detail needed for such adverse conditions to quality (i.e., scram events) and greatly improved their root cause evaluations in the subsequent evaluations performed for the January 14, 2013, July 30, 2013, and March 17, 2014, unplanned scram events. The level of details presented were greatly enhanced and proved that during our inspection period, the licensee understood the importance of performing proper evaluations to determine root and contributing causes for such significant events. The inspectors also noted that more resources, both people and time, were available to perform the subsequent root cause evaluations versus the inadequate resources available during the current transformer scram events due to the outage period and other issues.

The root causes and contributing causes as identified by the licensee for each scram event are noted in the table below:

Date of Scram Event	Root Cause(s)	Contributing Cause(s)	Major Corrective Action(s)
12/29/2012	1) Inadequate workmanship in maintaining clearance specified by the manufacturer for the CT	None Identified	<ul style="list-style-type: none"> • Micarta plate bolts were removed and/or thread cut to ensure cold clearance of 0.5" between the current transformer and the micarta plate bolts
01/04/2013	Same as the 12/29/2012 event.	Same as the 12/29/2012 event.	Same as the 12/29/2012 event.
01/14/2013	1) Design configuration of the horizontal busing 2) Degraded viewing port allowed water accumulation	1) Previous condition reports did not conduct adequate inspection.	<ul style="list-style-type: none"> • Covers installed over viewing ports. • 'B' phase flex links were cut out per EC 42117 • 'A' and 'C' phase bus bars were cut out per EC 42119 • Reinstitute the PM for

			performing the isophase bus duct inspection
07/30/2013	<ol style="list-style-type: none"> 1) Inadequate troubleshooting to validate the cause for alarm "TSE STU Cab Failure" 2) Inadequate TSE Restoration process for actual TSE System conditions 	<ol style="list-style-type: none"> 1) Inadequate risk recognition and mitigation 2) Inadequate maintenance, operations, production, and engineering knowledge of TSE system 3) Equipment failure of the TSE N30N011B temperature transmitter 	<ul style="list-style-type: none"> • Reinforce the requirements to use EN-MA-125 for emergent work • Revise Ops SOI 04-1-01-N32-2 to include a new step with instructions on how to turn TSE off/on • Revise ARI to include referring to SOI for instructions on turning TSE off/on • Revise model work orders to include TSE restoration steps • Revise Procedure 02 S-01-41 to include the Activity Evaluation Checklist for low to normal risk emergent activities • Generate an EC to utilize TSE influence during startup only • Operations, Engineering, and Maintenance training
03/17/2014	<ol style="list-style-type: none"> 1) Engineering risk assessment and mitigation process did not thoroughly challenge the design concept and did not specify sufficient performance evaluation 	<ol style="list-style-type: none"> 1) The as-built cantilevered piping support analyzed by LPI as "rigid" during EC 42426 preparation was flexible 	<ul style="list-style-type: none"> • Implement EC 49880 for power range neutron monitoring system to supply signal to the RPS • Revise EN-HU-104 to require that a Risk Rank 1 product be developed by a party with specialized subject matter expertise • The three engineers involved in the EC had their EC development qualifications removed until formal remediation was successfully completed

- c. *Determine whether the licensee's root cause evaluation included consideration of prior occurrences of the problem and knowledge of prior operating experience.*

The inspectors determined that the root cause evaluations included consideration of prior occurrences of the problem and knowledge of prior operating experience. However, the inspectors also noted that the licensee missed some important considerations during its operating experience review for the isophase bus duct scram event. As a result, we are documenting one non-cited violation with a P.5 cross-cutting aspect, characterized as failure to use operating experience (as documented in 4OA3.3).

Observation

Overall, the licensee's root cause evaluations identified both internal and external operating experience items that were relative to all five unplanned scram events. These items were used to help develop their corrective actions. However, in the January 14, 2013, unplanned scram event, the inspectors concluded that the licensee failed to identify the 2002 condition report that discussed the susceptibility of the isophase bus duct viewing ports to in-leakage of water. This is thoroughly discussed in the Green non-cited violation documented in Section 4OA3.3 of this report.

- d. *Determine whether the licensee's root cause evaluation addressed extent of condition and extent of cause of the problem.*

Overall, the inspectors determined that the root cause evaluations adequately addressed the extent of condition and extent of cause for each scram issue. The root cause evaluations adequately reviewed the extent of issues associated with the contributing causes identified as well. In some cases, the licensee performed extent of condition walkdowns with management oversight to ensure that any extending issues would be identified. However, the inspectors determined there were some issues with the licensee's extent of condition and extent of cause evaluations performed.

Observation

Specifically, the inspectors determined that the root cause evaluation for the scrams associated with the current transformer short to ground event did not fully address the extent of condition and extent of cause. Conversely, the subsequent root cause evaluations performed fully encompassed them. As a result, the corrective actions proposed for the subsequent scrams, if fully implemented, should address the root and contributing causes. In the isophase bus duct scram event, the inspectors noted that the extent of condition and extent of cause evaluations were narrowly focused. Consequently, the licensee failed to properly identify the root cause and missed a couple contributing causes. This was discussed with the licensee and properly documented in their corrective action program.

- e. *Determine whether the licensee's root cause evaluation, extent of condition, and extent of cause appropriately considered the safety culture components as described in IMC 0310.*

The inspectors determined that the root cause, extent of condition, and extent of cause evaluations, when fully performed, appropriately considered the safety culture components as currently described in IMC 0310, "Aspects Within the Cross-Cutting Areas," dated December 19, 2013.

The inspectors reviewed the root cause evaluations and validated that the licensee had systematically considered the safety culture components. In fact, Attachment 9.6 to licensee Procedure EN-LI-118, "Cause Evaluation Process," requires a review of the elements and aspects of the NRC safety culture components to determine which are associated with the root and contributing causes of the event. Overall, the licensee determined that the events were associated with human performance issues, decision making, and work practices. These were addressed in the licensee's corrective actions proposed and implemented.

The licensee conducted three separate commonality reviews to assess the safety culture issues and common threads amongst all the scram events. As a result, the licensee determined there were four common issues that, in general, trended throughout the scram events. These four predominant themes were considered organizational and programmatic (O&P) issues. They were noted as the following:

1. Inadequate workmanship of supplemental workers and supervisors
2. Inadequate details provided in engineering changes
3. Inadequate work order details planned by supplemental workers
4. Inadequate post modification testing complemented by supplemental engineers

One observation made by the inspectors, as conveyed to the licensee, was that the commonality issues seemed to heavily focus on the supplemental workers and not so much on the licensee. This could lead to a sense of misplaced fault and a failure to properly address the issues. The licensee understood our concern and committed to addressing the issue. In fact, they have already implemented site-wide training for their staff to discuss risk and technical tasks in relationship with the O&P issues identified.

In addition to our concern for a narrowly focused commonality review, we also offered the licensee our thoughts on two additional trending issues or commonalities among the scram events. Those two issues, considered as key issues by the inspectors, were Management Oversight and Overconfidence. These two issues seemed to play some level of fault in each scram event. Yet, the licensee never really characterized them as a contributing cause or commonality amongst the unplanned scrams. These concerns were also understood by the licensee and were being addressed in separate condition reports.

- f. Findings

No findings were identified.

2.03 Corrective Actions

- a. *Determine whether the licensee specified appropriate corrective actions for each root/contributing cause or that the licensee evaluated why no actions were necessary.*

The inspectors reviewed each of the root and apparent cause evaluations performed and their associated corrective actions. The corrective actions were clearly described and were entered into and tracked by the licensee's corrective action program. These corrective actions are noted in the table listed above in Section 2.02(b). Regarding these actions, the inspectors did present the concern that some corrective actions are susceptible to getting lost in the process by being closed out to different actions and/or documents. The licensee assured us that they are paying close attention and plan to track each corrective action to its closure.

- b. *Determine whether the licensee prioritized the corrective actions with consideration of the risk significance and regulatory compliance.*

The inspectors determined that the licensee adequately prioritized the corrective actions with consideration of the risk significance and regulatory compliance. The inspectors reviewed the prioritization of the corrective actions and verified that, within reason, actions of a generally higher priority were scheduled for completion ahead of those of a lower priority. While many of the corrective actions were completed, some have not yet been completed. The licensee assured us that each corrective action will be tracked to its closure. One concern noted was that some corrective actions were general fixes and were done expeditiously. This was particularly identified in the January 14, 2013, evaluation. Again, subsequent evaluations seemed to have corrected this issue and addressed the corrective actions appropriately.

- c. *Determine whether the licensee established a schedule for implementing and completing the corrective actions.*

The inspectors determined that the licensee adequately established a schedule for implementing and completing the corrective actions. The schedule is tracked in the licensee's corrective action program system. As discussed above, while many of the corrective actions were completed, some have not yet been completed. The remaining corrective actions have been scheduled along with effectiveness reviews. The inspectors concluded the timeline for completion of corrective actions was appropriate.

- d. *Determine whether the licensee developed quantitative or qualitative measures of success for determining effectiveness of the corrective actions to prevent recurrence.*

The inspector determined that the licensee adequately developed quantitative or qualitative measures of success for determining the effectiveness of the corrective actions to prevent recurrence. An Effectiveness Review Plan has been created to determine the method, attributes, acceptance criteria, and schedule for effectiveness reviews. The inspectors concluded the effectiveness reviews were appropriate.

- e. *Determine that the corrective actions planned or taken adequately address the Notice of Violation that was the basis for the supplemental inspection.*

The NRC staff did not issue a Notice of Violation to the licensee; therefore, this inspection item was not applicable.

- f. Findings

No findings were identified.

2.04 Evaluation of IMC 0305 Criteria For Treatment Of Old Design Issues

No old design issues were identified; therefore, this inspection item was not applicable.

40A6 Meetings, Including Exit

Exit Meeting Summary

On June 20, 2014, the inspectors presented the inspection results to Mr. K. Mulligan, Site Vice President, Operations, and other members of the licensee staff. The licensee acknowledged the issues presented. The licensee confirmed that any proprietary information reviewed by the inspectors had been returned or destroyed. The inspectors re-exited with Mr. J. Nadeau, Director of Performance Improvement and Regulatory Assurance, and other members of the licensee staff on August 6, 2014, due to some changes made to the initially discussed findings.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

R. Benson, Superintendent, Radiation Protection
C. Beschett, Manager, Nuclear Oversight
S. Burd, Manager, Systems Engineering
D. Byrnes, Manager, Finance
T. Coles, Licensing Engineer, Regulatory Assurance
D. Cooley, Consultant, Regulatory Assurance
J. Dorsey, Manager, Security
M. Goodwin, Manager, Operations
J. Miller, General Manager, Plant Operations
M. Milly, Senior Manager, Maintenance
E. Meadows, Manager, Training
K. Mulligan, Site Vice President
J. Nadeau, Manager, Regulatory Assurance
P. Salgad, Manager, Performance Improvement
R. Scarbrough, Specialist, Regulatory Assurance
J. Seiter, Senior Licensing Specialist, Regulatory Assurance
T. Thornton, Manager, Design Engineering

NRC Personnel

B. Rice, Senior Resident Inspector

LIST OF ITEMS OPENED AND CLOSED

Opened

None

Opened and Closed

05000416/2014009-01	FIN	Failure To Correct Degraded Viewing Ports In A Timely Manner (Section 4OA3.3)
05000416/2014009-02	NCV	Failure To Correct A Significant Condition Adverse To Quality And Preclude Repetition (Section 4OA3.5)

Closed

05000416/2012-008-00	LER	Automatic Reactor Scram Due to a Main Turbine Generator Trip Initiated By the 'A' Phase Unit Differential Relay (Section 4OA3.1)
05000416/2013-001-00	LER	Automatic Reactor Scram Due to a Main Turbine Generator Trip Initiated by the 'A' Phase Unit Differential Relay (Section 4OA3.2)
05000416/2013-002-00	LER	Automatic Reactor Scram Due to a Main Turbine Generator Trip Initiated by a Main Generator Neutral Ground Relay Trip (Section 4OA3.3)
05000416/2013-003-00	LER	Unanticipated Reduction In Load Demand and Subsequent Main Turbine Control Valve Closure Resulting in an Unplanned Reactor Scram From a Reactor Pressure Transient (Section 4OA3.4)
05000416/2014-002-00	LER	Manual Actuation of the Reactor Protection System Due to Steam Leak with Reactor Core Isolation Cooling Manual Initiation (Section 4OA3.5)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Procedures

<u>Number</u>	<u>Title</u>	<u>Revision/Date</u>
EN-LI-102	Corrective Action Process	23
EN-LI-118	Cause Evaluation Process	20
EN-MA-125	Troubleshooting Control of Maintenance Activities	14
05-1-02-1-1	Off-Normal Event Procedure Reactor Scram	117 - 121
05-1-02-1-2	Off-Normal Event Procedure Turbine And Generator Trips	32 - 35
05-S-01-EP-1	Emergency Procedure Emergency/Severe Accident Procedure Support Documents	32/43
EN-OP-104	Operability Determination Process	7

Condition Reports (CRs)

CR-GGN-2002-01858	CR-GGN-2012-01842	CR-GGN-2012-13290	CR-GGN-2013-00083
CR-GGN-2013-00100	CR-GGN-2013-00319	CR-GGN-2013-00538	CR-GGN-2013-04943
CR-GGN-2013-07535	CR-GGN-2014-02824	CR-GGN-2014-03131	

Miscellaneous Documents

<u>Number</u>	<u>Title</u>	<u>Revision/Date</u>
24-507-81881	Attachment for Current Transformer Mounting	0
EC No. 20838	Installation of New HV and Neutral Bushings and New Current Transformers	0
WO-GGN- 00251399	Replace the HV Bushings and CT's In Bushing Box/EC20838	
WO-GGN-00358224	Terminal Strip Assembly Is Degraded/Cracked	
GGNS LER 2012-002	Manual Reactor Scram Due to a Steam Supply	April 19, 2012

<u>Number</u>	<u>Title</u>	<u>Revision/Date</u>
	Motor Operated Valve Failure that Resulted in the Inability to Maintain Reactor Water Level	
GGNS LER 2012-008	Reactor Protection System Actuation Due to a Main Turbine Generator Trip	February 27, 2013
GGNS LER 2013-001	Reactor Protection System Actuation Due to a Main Turbine Generator Trip	March 4, 2013
GGNS LER 2013-002	Reactor Protection System Actuation Due to a Turbine Trip	March 15, 2013
GGNS LER 2013-003	Reactor Protection System and Reactor Core Isolation Cooling Actuation Due to a High Reactor Pressure Transient	September 26, 2013
	Pre-NRC 95001 Inspection Snapshot Self-Assessment	January 6, 2014
SSA 95001	Review Pre-NRC 95001 Inspection Snapshot Assessment Report	January 16, 2014
GGNS LER 2014-002	Manual actuation of the Reactor Protection System Due to Steam Leak with Reactor Core Isolation Cooling Manual initiation	March 17, 2014
GGNS LER 2014-003	Automatic Actuation of the Reactor Protection System (RPS) Due to Main Turbine Overspeed Protection Load Reject Relay Fault	March 29, 2014
CR-GGN-2012-1842	Root Cause Evaluation Report Inability to Maintain Reactor Water Level	5
CR-GGN-2013-4943	Root Cause Evaluation Report Turbine Stress Evaluator SCRAM	0
CR-GGN-2014-2824	Root Cause Evaluation Steam Leak on Main Steam Line Resulting in Scram 134	0
VM 460000352	Isophase Bus Duct Vendor Manual	0