UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
612 EAST LAMAR BLVD, SUITE 400
ARLINGTON, TEXAS 76011-4125

November 9, 2011

Mr. Edward D. Halpin,
President and Chief Executive Officer
STP Nuclear Operating Company
P.O. Box 289
Wadsworth, TX 77483

Subject: SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000498/2011004 AND 05000499/2011004

Dear Mr. Halpin:

On September 30, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your South Texas Project Electric Generating Station, Units 1 and 2, facility. The enclosed integrated inspection report documents the inspection findings, which were discussed on October 6, 2011, with Mr. M. Meier, Vice President and Assistant to the President and Chief Executive Officer, and other members of your staff.

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

Based on the results of this inspection, one self-revealing and two NRC identified findings were evaluated under the significance determination process as having very low safety significance (Green). The NRC has determined that violations are associated with these findings. Additionally, two licensee-identified violations, which were determined to be of very low safety significance, are listed in this report. However, because of the very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as noncited violations, consistent with Section 2.3.2 of the NRC Enforcement Policy.

If you contest these violations or the significance of these noncited violations, 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, 612 E. Lamar Blvd, Suite 400, Arlington, Texas, 76011-4125; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the 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 IV, and the NRC Resident Inspector at the facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if you choose to provide one for cases where a response is not required, will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html. To the extent possible, your response should not include any personal privacy or proprietary information so that it can be made available to the Public without redaction.

Sincerely,

/RA/

Wayne Walker, Chief
Project Branch A
Division of Reactor Projects

Dockets: 50-498
50-499
Licenses: NPF-76
NPF-80

Enclosure:
NRC Inspection Report 05000498/2011004 and 05000499/2011004
w/Attachment: Supplemental Information

cc w/Enclosure: Distribution via Listserv

Electronic distribution by RIV:
Regional Administrator (Elmo.Collins@nrc.gov)
Deputy Regional Administrator (Art.Howell@nrc.gov)
DRP Director (Kriss.Kennedy@nrc.gov)
DRP Deputy Director (Troy.Pruett@nrc.gov)
DRS Director (Anton.Vegel@nrc.gov)
DRS Deputy Director (Tom.Blount@nrc.gov)
Senior Resident Inspector (John.Dixon@nrc.gov)
Resident Inspector (Binesh.Tharakan@nrc.gov)
Branch Chief, DRP/A (Wayne.Walker@nrc.gov)
Senior Project Engineer, DRP/A (David.Proulx@nrc.gov)
Project Engineer, DRP/A (Christopher.Henderson@nrc.gov)
Project Engineer, DRP/A (Jason.Dykert@nrc.gov)
STP Administrative Assistant (Lynn.Wright@nrc.gov)
Public Affairs Officer (Victor.Dricks@nrc.gov)
Public Affairs Officer (Lara.Uselding@nrc.gov)
Project Manager (Balwant.Singal@nrc.gov)
Acting Branch Chief, DRS/TSB (Dale.Powers@nrc.gov)
RITS Coordinator (Marisa.Herrera@nrc.gov)
Regional Counsel (Karla.Fuller@nrc.gov)
Congressional Affairs Officer (Jenny.Weil@nrc.gov)
OEMail Resource
ROPreports
RIV/ETA: OEDO (Mark.Franke@nrc.gov)
Regional State Liaison Officer (Bill.Maier@nrc.gov)
NSIR/DPR/EP (Eric.Schrader@nrc.gov)

R:\REACTORS\STP\2011\STP2011-04RP-JLD.doc

SUNSI Rev Compl.	☒ Yes ☐ No	ADAMS	☒ Yes ☐ No	Reviewer Initials	Ww
Publicly Avail	☒Yes ☐ No	Sensitive	☐ Yes ☒ No	Sens. Type Initials	Ww

RI:DRP/PBA	SRI:DRP/PBA	SPE:DRP/PBA	C:DRS/PSB2	C:DRS/OB
BKTharakan	JLDixon	DLProulx	GEWerner	MSHaire
T-WALKER	**T-WALKER**	**/RA/**	**/RA/**	**/RA/**
11/7/11	11/7/11	11/8/11	11/1/11	11/2/11
C:DRS/PSB1	C:DRS/EB1	C:DRS/EB2	C:DRS/TSB	C:DRP/PBA
MCHay	TRFarnholtz	NFO'Keefe	DAPowers	WCWalker
/RA/	**/RA/**	**/RA/**	**/RA/**	**/RA/**
11/2/11	11/2/11	11/2/11	11/2/11	11/8/11

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	05000498, 05000499
License:	NPF-76, NPF-80
Report:	05000498/2011004 and 05000499/2011004
Licensee:	STP Nuclear Operating Company
Facility:	South Texas Project Electric Generating Station, Units 1 and 2
Location:	FM521 - 8 miles west of Wadsworth Wadsworth, Texas 77483
Dates:	July 1 through September 30, 2011
Inspectors:	J. Dixon, Senior Resident Inspector M. Chambers, Resident Inspector, Cooper Nuclear Station J. Dykert, Project Engineer G. Guerra, Certified Health Physicist, Emergency Preparedness Inspector S. Hedger, Operations Engineer S. Makor, Reactor Inspector D. Proulx, Senior Project Engineer B. Tharakan, CHP, Resident Inspector J. Watkins, Reactor Inspector M. Young, Reactor Inspector
Approved By:	Wayne Walker, Chief, Project Branch A Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000498/2011004, 05000499/2011004; 07/01/2011 – 09/30/2011; South Texas Project Electric Generating Station, Units 1 and 2, Integrated Resident and Regional Report; Operability Evaluations; Identification and Resolution of Problems.

The report covered a 3-month period of inspection by resident inspectors and an announced baseline inspection by a regional based inspector. Five Green noncited violations of very low safety significance were identified, two NRC identified, one self-revealing, and two licensee-identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." The cross-cutting aspect is determined using Inspection Manual Chapter 0310, "Components Within the Cross-Cutting Areas." Findings for which the significance determination process 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," Revision 4, dated December 2006.

A. NRC-Identified Findings and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors reviewed a self-revealing noncited violation of Technical Specification 6.8.1.a, for the failure to follow maintenance work authorization number 416904. Specifically on January 27, 2011, mechanics incorrectly aligned the fuel oil delivery valve stop and spring on standby diesel generator 13 cylinder 1R. On July 17, 2011, the control room received an alarm for standby diesel generator 13 because the crankcase lubricating oil level was high out of band. After operability testing on July 15, 2011, fuel oil leaked through cylinder 1R into the crankcase because the spring broke creating foreign material that fouled the injector nozzle. The licensee corrected the error, replaced the spring, and restored operability of the diesel.

  The finding was more than minor because it affected the Mitigating Systems Cornerstone attribute of Human Performance, and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences because it caused the diesel to be inoperable. The inspectors used NRC Inspection Manual Chapter 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," dated January 10, 2008, to determine the significance of the finding because it affected the Mitigating Systems Cornerstone while the plant was at power. The finding was determined to be of very low safety significance because it was not a design or qualification deficiency; it did not represent a loss of a system safety function; it did not represent the loss of a single train for greater than technical specification allowed outage time; it did not represent a loss of one or more nontechnical specification risk-significant equipment for greater than 24 hours; and it did not screen as potentially risk significant due to seismic, flooding, or severe weather. In addition, this finding had human performance cross-cutting aspects associated with work practices because the licensee did not communicate human error prevention techniques, such as self and peer checking, commensurate with the risk, such that the work activity was performed safely [H.4(a)](Section 1R15).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criteria XVI, “Corrective Action,” for the failure to assure that conditions adverse to quality were promptly identified and corrected. Specifically, the licensee did not promptly identify and correct improperly installed temperature switches. On October 28, 2010, the Unit 2 essential cooling water vent fan 21A failed because the control power fuse blew due to an unused uninsulated wire. The root cause investigation determined that the unused wire had been installed when the switch was replaced in February 2005. The extent of condition review identified that a total of 60 switches had been replaced, but only one additional switch was verified and it also had an unused uninsulated wire. After inspector questioning, the licensee inspected the 12 actuation switches and determined that only the Unit 2 essential cooling water vent fans for trains A and C were affected. The licensee’s corrective actions included: performing an immediate and prompt operability, performing training with the maintenance personnel on the procedural requirements for unused wires, and scheduling the inspection of the 48 high/high temperature switches commensurate with risk significance.

  This finding was more than minor because it was associated with the Mitigating Systems Cornerstone attributes of Design Control, Equipment Performance, and Human Performance and it affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The deficiency resulted in a potential inoperability of Unit 2 essential cooling water trains A and C since 2005. The senior resident inspector performed the initial significance determination for the essential cooling water issue using the NRC Inspection Manual Chapter 0609, Attachment 0609.04, “Phase 1 – Initial Screening and Characterization of Findings.” The finding screened to a Phase 2 significance determination because it involved an actual loss of safety function of two single trains of equipment for greater than the technical specification allowed outage time. A Region IV senior reactor analyst attempted to perform a Phase 2 significance determination using the pre-solved worksheets, but the Phase 2 process was not well suited for this issue. Therefore, the senior reactor analyst performed a bounding Phase 3 significance determination and found the finding to be of very low safety significance. The dominant core damage sequence included: seismic initiated loss of offsite power, failure of the essential cooling water trains A and C, failure of the train B emergency diesel generator, and failure to recover the diesel or offsite power in 4 hours. The low frequency of seismic induced loss of offsite power events at South Texas Project and the unaffected train B essential cooling water train helped to mitigate the finding’s significance. In addition, this finding had human performance cross-cutting aspects associated with decision-making, in that, the licensee failed to use conservative assumptions and verify the validity of the underlying assumptions [H.1(b)] (Section 1R15).

- Green. The inspectors identified a noncited violation of 10 CFR Part 50, Appendix B, Criteria XVI, "Corrective Action," for the failure to assure that conditions adverse to quality were promptly identified and corrected. Specifically, the inspectors determined that operations had no instructions for manual control of the 4160 Vac load tap changing transformers. Procedure 0POP02-AE-0002, "Transformer Normal Breaker and Switch Lineup," was not revised providing these instructions. In December 2010, Unit 2 experienced a material issue with the load tap changer, which required operations to take manual control of the load tap changer without procedure guidance. Subsequently, the licensee issued an operation's standing order to allow for manual operations, but did not revise the procedure. In May 2011, the licensee experienced another material condition issue with the Unit 2 load tap changer that required operations to take manual control of the load tap changer, but since the procedure was never revised, operations found themselves operating the plant outside of procedures again. Corrective actions included revising Procedure 0POP02-AE-0002, to include manual operation of the load tap changer, and training all the operations personnel on the new procedure.

  This finding was more than minor because it was associated with the Mitigating Systems Cornerstone attributes of Design Control and Procedure Quality, and it affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The deficiency resulted in operations not having any guidance on how to control the Units 1 and 2 train B 4160 Vac transformer load tap changer to ensure that the bus remained within technical specification surveillance requirement voltage limits. The inspectors performed the significance determination using NRC Inspection Manual Chapter 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," dated January 10, 2008, because it affected the Mitigating Systems Cornerstone while the plant was at power. The finding was determined to be of very low safety significance because it was not a design or qualification deficiency; it did not represent a loss of safety system function; it did not represent the loss of a single train for greater than technical specification allowed outage time; it did not represent a loss of one or more non-technical specification risk-significant equipment for greater than 24 hours; and it did not screen as potentially risk significant due to seismic, flooding, or severe weather. In addition, this finding had human performance cross-cutting aspects associated with decision making, in that, the licensee failed to communicate decisions and the basis for decisions to personnel who have a need to know the information to perform work safely [H.1(c)] (Section 4OA2).

B. Licensee-Identified Violations

Violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers (condition report numbers) are listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent rated thermal power and essentially remained there for the remainder of the inspection period.

Unit 2 began the inspection period at 100 percent rated thermal power and remained there until August 14, 2011, when the unit reduced power to 18 percent to remove the unit auxiliary transformer from service for maintenance. The unit returned to 100 percent rated thermal power on August 16, 2011, and remained there until August 19, 2011, when the unit reduced power to 14 percent to restore the unit auxiliary transformer following maintenance. The unit returned to 100 percent rated thermal power on August 22, 2011, and essentially remained there for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors performed a review of the adverse weather procedures for seasonal extremes (e.g., extreme high temperatures, extreme low temperatures, or hurricane season preparations). The inspectors verified that weather-related equipment deficiencies identified during the previous year were corrected prior to the onset of seasonal extremes; and evaluated the implementation of the adverse weather preparation procedures and compensatory measures for the affected conditions before the onset of, and during, the adverse weather conditions.

During the inspection, the inspectors focused on plant-specific design features and the procedures used by plant personnel to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the UFSAR and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant-specific procedures. Specific documents reviewed during this inspection are listed in the attachment. The inspectors also reviewed corrective action program items to verify that plant personnel were identifying adverse weather issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- July 27, 2011, Units 1 and 2, walkdown of systems contained in the isolation valve cubicle rooms [auxiliary feedwater (AFW), main steam and main feedwater], the switchyard, and the engineered safety features (ESF) transformers

These activities constitute completion of one readiness for seasonal adverse weather sample as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings were identified.

.2 Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

Since thunderstorms with potential tornados and high winds were forecast in the vicinity of the facility as a result of Tropical Storm Don for July 27-29, 2011, the inspectors reviewed the plant personnel's overall preparations/protection for the expected weather conditions. On July 29, 2011, the inspectors walked down the Unit 1 and 2 essential cooling water (ECW) system, electrical switchyard, and ESF transformers because their safety-related functions could be affected, or required, as a result of high winds or tornado-generated missiles or the loss of offsite power. The inspectors evaluated the plant staff's preparations against the site's procedures and determined that the staff's actions were adequate. During the inspection, the inspectors focused on plant-specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the UFSAR and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant-specific procedures. The inspectors also reviewed a sample of corrective action program items to verify that the licensee-identified adverse weather issues at an appropriate threshold and dispositioned them through the corrective action program in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one readiness for impending adverse weather condition sample as defined in Inspection Procedure 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignments (71111.04)

Partial Walkdown

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- July 29, 2011, Unit 2, ECW train B

- September 28, 2011, Unit 2, component cooling water train B

The inspectors selected these systems based on their risk significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors evaluated any discrepancies that could affect the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, UFSAR, technical specification requirements, administrative technical specifications, outstanding work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also inspected accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of two partial system walkdown samples as defined in Inspection Procedure 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

Quarterly Fire Inspection Tours

a. Inspection Scope

The inspectors conducted fire protection walkdowns that were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- July 20, 2011, Unit 1, isolation valve cubicle train, main steam, and feedwater penetration area train C, Fire Zone 406 and fire water storage tank #1 preventive maintenance

- July 21, 2011, Unit 2, isolation valve cubicle, main steam, and feedwater penetration area train C, Fire Zone 406 and fire water storage tank #1 preventive maintenance

- September 27, 2011, Unit 1, isolation valve cubicle, main steam, main feedwater, and AFW penetration area train B, Fire Zones Z402 and Z407

- September 27, 2011, Unit 2, isolation valve cubicle, main steam, main feedwater, and AFW penetration area train B, Fire Zones Z402 and Z407

The inspectors reviewed areas to assess if licensee personnel had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant; effectively maintained fire detection and suppression capability; maintained passive fire protection features in good material condition; and had implemented adequate compensatory measures for out of service, degraded or inoperable fire protection equipment, systems, or features, in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to affect equipment that could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four quarterly fire protection inspection samples as defined in Inspection Procedure 71111.05-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On August 1, 2011, the inspectors observed a crew of licensed operations personnel in the plant's simulator to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- Licensed operator performance
- Crew's clarity and formality of communications
- Crew's ability to take timely actions in the conservative direction
- Crew's prioritization, interpretation, and verification of annunciator alarms
- Crew's correct use and implementation of abnormal and emergency procedures
- Control board manipulations

- Oversight and direction from supervisors
- Crew’s ability to identify and implement appropriate technical specification actions and emergency plan actions and notifications

The inspectors compared the crew’s performance in these areas to pre-established operator action expectations and successful critical task completion requirements. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one quarterly licensed-operator requalification program sample as defined in Inspection Procedure 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- July 22, 2011, Units 1 and 2, main steam [MS] system
- September 1, 2011, Units 1 and 2, 13.8 – 4.16 kVac non-class 1E [PC, PD, and PG] systems
- September 26, 2011, Units 1 and 2, electrohydraulic controls [EH]

The inspectors reviewed events such as where ineffective equipment maintenance has resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee’s actions to address system performance or condition problems in terms of the following:

- Implementing appropriate work practices
- Identifying and addressing common cause failures
- Scoping of systems in accordance with 10 CFR 50.65(b)
- Characterizing system reliability issues for performance
- Charging unavailability for performance
- Trending key parameters for condition monitoring
- Ensuring proper classification in accordance with 10 CFR 50.65(a)(1) or -(a)(2)

- Verifying appropriate performance criteria for structures, systems, and components classified as having an adequate demonstration of performance through preventive maintenance, as described in 10 CFR 50.65(a)(2), or as requiring the establishment of appropriate and adequate goals and corrective actions for systems classified as not having adequate performance, as described in 10 CFR 50.65(a)(1)

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the corrective action program with the appropriate significance characterization. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three quarterly maintenance effectiveness samples as defined in Inspection Procedure 71111.12-05.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors reviewed licensee personnel's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- July 18-25, 2011, Unit 1, standby diesel generator (SDG) 13 fuel oil leak on cylinder 1R and Unit 2, train C sequencer testing

- August 14-22, 2011, Unit 2, unit auxiliary transformer unplanned maintenance to repair the load tap changer, including reducing power to approximately 15 percent and returning to full power to remove and to restore the transformer to service

- September 5-9, 2011, Units 1 and 2, planned maintenance activities on Unit 1 train C large work week and emergent activities on centrifugal charging pump 1B, and Unit 2 train B, including first time testing of remote shutdown system operability

- September 19-24, 2011, Units 1 and 2, planned maintenance activities on Unit 1 train A large work week including north bus outage, and Unit 2 train D, including emergent work to repair a rod control urgent alarm

The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that licensee personnel performed risk assessments as required by

10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When licensee personnel performed emergent work, the inspectors verified that the licensee personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed the technical specification requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four maintenance risk assessments and emergent work control inspection samples as defined in Inspection Procedure 71111.13-05.

b. Findings

No findings were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- July 28, 2011, Units 1 and 2, reactor vessel water level cabinets, power supply cable harness current rating may be less than the maximum loading
- September 23, 2011, Unit 1, SDG 13 1R cylinder fuel oil delivery valve stop and spring incorrectly aligned
- September 29, 2011, Units 1 and 2, Static-O-Ring temperature switches installed in Units 1 and 2 AFW, Unit 2 ECW water, and Unit 1 liquid waste processing system high energy line break locations
- September 30, 2011, Units 1 and 2, 13.8 kVac, 4160 Vac, and 480 Vac operating ranges following design change package that implemented new 13.8 kVac and 4160 Vac bands

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that technical specification operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the technical specifications and UFSAR to the licensee personnel's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of four operability evaluations inspection samples as defined in Inspection Procedure 71111.15-05.

b. Findings

.1 SDG 13 Fuel Oil Delivery Valve Stop and Spring

Introduction. The inspectors reviewed a self-revealing Green noncited violation of Technical Specification 6.8.1.a, for the failure to follow maintenance procedures to correctly align the pilot spring and stop inside the fuel delivery valve of the 1R cylinder on SDG 13.

Description. On July 17, 2011, the control room received a trouble alarm for SDG 13. Operations staff sent a plant operator into the SDG 13 room to investigate. The operator reported back to the control room that the lube oil crankcase oil level was high out of band and the color of the lube oil was red. Normal lubricating oil is a brown color, fuel oil is a red color. This indicated that there was a fuel oil leak into the crankcase. The licensee declared SDG 13 inoperable and began troubleshooting and investigating the issue. The licensee identified that only the 1R cylinder was leaking fuel oil into the cylinder through the fuel oil delivery valve and nozzle. The licensee removed the delivery valve and nozzle and sent them offsite for analysis. The results of the analysis showed that the fuel oil delivery valve spring was broken and the valve stop had been installed incorrectly. The correct orientation of the valve stop and spring was that the spring is under the stop. However, when the valve holder was disassembled for inspection, it was discovered that stop was under the spring, the orientation was reversed.

The licensee performed a root cause investigation of this event, and determined that on January 27, 2011, the licensee performed maintenance on cylinder 1R to install an ultra low sulfur diesel fuel oil kit. This maintenance required the licensee to disassemble the fuel injector pump fuel oil delivery valve holder and install a new o-ring. During reassembly of the delivery valve holder, the spring and stop were incorrectly aligned and reinstalled into the valve holder. The investigation team determined that operation of SDG 13 resulted in the spring breaking apart causing the fuel delivery valve stop to fail. Further operation of SDG 13 eventually caused the foreign material created by the broken spring to reach the fuel injector nozzle resulting in its failure, which caused fuel oil to leak down through cylinder 1R and into the lube oil crankcase while SDG 13 was in standby.

On July 15, 2011, the licensee secured SDG 13 from a monthly operability test, which it passed satisfactorily. However, the root cause investigation team determined that fuel oil began leaking past the nozzle valve into the cylinder after SDG 13 was secured because the level in the fuel oil storage tank showed a decreasing trend from July 15 to July 17, when the control room received the trouble alarm. The inspectors reviewed the root cause, work instructions, procedures, and interviewed the personnel involved with the event. The inspectors determined that a performance deficiency occurred when the workers failed to follow work authorization number 416904 work instructions to ensure that SDG 13 cylinder 1R delivery valve pilot spring and stop were correctly aligned. During the interviews with maintenance craft and root cause investigators, the inspectors also determined that the licensee did not identify or implement human performance error prevention tools in accordance with station Procedure 0PGP03-HU-0001, "Human Performance (HU) Program," Revision 0, which resulted in the workers not verifying the installation of the valve spring and stop were correct.

Analysis. The finding was more than minor because it was associated with the Mitigating Systems Cornerstone attributes of Procedure Quality and Human Performance, and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences because it caused the inoperability of SDG 13. The inspectors used NRC Inspection Manual Chapter 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," dated January 10, 2008, to determine the significance of the finding because it affected the Mitigating Systems Cornerstone while the plant was at power. The finding was determined to be of very low safety significance (Green) because it was not a design or qualification deficiency; it did not result in the loss of a system safety function; it did not represent the loss of a single train for greater than technical specification allowed outage time; it did not represent a loss of one or more nontechnical specification risk-significant equipment for greater than 24 hours; and it did not screen as potentially risk significant due to seismic, flooding, or severe weather. In addition, this finding had human performance cross-cutting aspects associated with work practices because the licensee did not communicate human error prevention techniques, such as self and peer checking, commensurate with the risk, such that the work activity was performed safely [H.4(a)].

Enforcement. Technical Specification 6.8.1.a states, in part, that written procedures shall be established, implemented, and maintained covering the activities referenced in Appendix A of Regulatory Guide 1.33, Revision 2, dated February 1978. Regulatory Guide 1.33, Appendix A, Section 9, Part a, requires procedures for performing maintenance on safety-related equipment. Maintenance work authorization number 416904 work instructions, step 3.3.4, required in part, to: "Place the delivery valve holder and delivery valve flange on pump being sure to align the pilot spring and stop correctly in the cavity of the delivery valve holder." Contrary to the above, on January 27, 2011, maintenance personnel failed to correctly align the pilot spring and stop. Because this finding was of very low safety significance and was entered into the licensee's corrective action program as Condition Report 11-11588, this finding is being treated as a noncited violation, consistent with Section 2.3.2 of the NRC Enforcement Policy: NCV 05000498/2011004-01, "Failure to Follow Standby Diesel Generator Maintenance Procedures."

.2 Static-O-Ring Temperature Switches

Introduction. The inspectors identified a Green noncited violation of 10 CFR Part 50, Appendix B, Criteria XVI, "Corrective Action," for the failure to assure that conditions adverse to quality were promptly identified and corrected.

Description. On October 28, 2010, the licensee discovered that ECW vent fan 21A on Unit 2 had no running indication. The control room dispatched an operator who confirmed that the fan was not running. This resulted in the licensee declaring Unit 2 ECW system train A inoperable. The licensee restored from the condition by replacing a blown control power fuse and insulating an unused wire associated with vent fan 21A temperature switch later the same day. The licensee performed a root cause investigation and determined that the unused uninsulated wire had been installed when the temperature switch was changed from a Johnson switch to a Static-O-Ring switch in February 2005. The original Johnson switch only had two wires and the Static-O-Ring switch came with three wires. The third unused wire was not capable of being removed from the new switch due to the design so it had to be protected during installation by either insulating or terminating to a spare connector. This level of detail was not included in the design change package or the work instructions that installed the switch. However the work instructions did reference Procedure 0PMP02-NZ-0013, "Cable Terminations," which did have a section that discusses how to handle spare wires. The maintenance craft failed to follow this procedure when they replaced the fan switch, see Section 4OA7 of this report for a licensee-identified violation. The root cause investigation extent of condition review identified that a total of 60 switches had been replaced and needed to be evaluated for similar installation deficiencies and therefore operability concerns. Of the 60 switches 12 were installed in actuation logic circuits (provided control signal to start the fan): four in Unit 1 AFW trains A, B, C and D; four in Unit 2 AFW trains A, B, C, and D; three in Unit 2 ECW trains A, and C; and one in Unit 1 associated with a high energy line break isolation. The remaining 48 were installed in temperature indication only logic circuits, high/high temperature switches, for Units 1 and 2 ECW, SDG, isolation valve cubicle, and mechanical auxiliary buildings.

The inspectors identified that the licensee only planned to inspect two of the ECW fans, and one of the two fans was the wrong fan. As a result, the licensee only verified one additional switch and it was found to also have an unused uninsulated wire. The inspectors pointed out that the extent of condition did not have adequate justification for continued operability for the entire function of AFW for both Units 1 and 2 or for Unit 2 ECW. Especially since the licensee had documented that both of the switches inspected to date were not insulated. This meant that the AFW and ECW systems may not be operable for all required design accident scenarios. After additional follow-up, based on the inspectors, questions only the Unit 2 ECW vent fans for trains A and C were affected by this condition. The inspectors determined that the licensee failed to verify their underlying assumptions. The licensee's corrective actions included: performing an immediate operability, performing a prompt operability, inspecting the 12 actuation switches, performing training with the maintenance personnel on the procedural requirements for unused wires, and scheduling the inspection of the 48 high/high temperature switches commensurate with risk significance.

Analysis. The failure to promptly identify and correct a condition adverse to quality that affected multiple trains and systems of safety-related equipment was a performance deficiency. This finding was more than minor because it was associated with the Mitigating Systems Cornerstone attributes of Design Control, Equipment Performance, and Human Performance, and it affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The deficiency resulted in a potential inoperability of Unit 2 ECW trains A and C since 2005. The senior resident inspector performed the initial significance determination using NRC Inspection Manual Chapter 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," dated January 10, 2008, because it affected the Mitigating Systems Cornerstone while the plant was at power. The finding screened to a Phase 2 significance determination because it involved an actual loss of safety function of two single trains of equipment for greater than the technical specification allowed outage time.

A Region IV senior reactor analyst attempted to perform a Phase 2 significance determination using the pre-solved worksheet from the "Risk Informed Inspection Notebook for South Texas Project Electric Generating Station," Revision 2.01a. However, the worksheets were not well suited for this particular finding (two of three ECW system trains being nonfunctional). Therefore, the analyst performed a bounding Phase 3 significance determination.

The analyst made the following influential assumptions:

- Each ECW pump room was equipped with two ventilation fans. The analyst conservatively assumed that both were required to support the function of an ECW system train. Trains A and C were potentially affected by the performance deficiency.

- The analyst assumed that the fan wire could short to ground through the conduit. If this occurred, the fan would become nonfunctional. The analyst gave no credit for prompt repair or recovery.

- Some type of forcing function would be required to cause a short to ground. During most conditions, no function existed. However, the wire could move during a seismic event. The analyst assumed that during a seismic event large enough to cause a loss of offsite power, the train A and train C fans would touch the conduit and short to ground, rendering both trains nonfunctional. The seismic loss of offsite power threshold was chosen because normal power is lost (as well as normal ventilation). The non-safety power conversion system would also be lost. Seismic events less than the loss of offsite power threshold would only result in noncomplicated transients (reactor trips).

- The "Risk Assessment of Operational Events, Volume 2 – External Events," Revision 1.01, specifies the initiating event frequency for a seismically induced loss of offsite power as 1.4E-5/year.

The analyst used the South Texas Project, Units 1 and 2, SPAR model, Revision 8.15, dated August 27, 2010, to calculate the conditional core damage probabilities for: 1) a seismically induced loss of offsite power initiating event (probability = 1.0) without a failed ECW train, and 2) a seismically induced loss of offsite power initiating event with two failed ECW trains (A & C). For the run with the failed trains, the analyst set the ECW pumps' "fail to start" basic events to a probability of 1.0. Since seismic initiated losses of offsite power are not considered recoverable, the analyst set the offsite power recovery values to 1.0 (recovery would fail). The analyst used a cutset truncation of 1.0E-11.

The conditional core damage probability for a loss of offsite power (no additional failures) was 3.0E-5. The conditional core damage probability for a seismically induced loss of offsite power with a loss of the two ECW trains was 2.9E-2. Therefore, the delta-CDF was (assuming a full year of exposure):

Delta-CDF = 1.4E-5 *(2.9E-2 – 3.0E-5) = 4.0E-7

Since the calculated change in core damage frequency was less than 1E-6, the finding was of very low safety significance (Green) for core damage.

Large Early Release Frequency: To evaluate the change to the large early release frequency, the analyst used Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process." South Texas Project has a large dry containment. The finding screened as having very low safety significance for large early release frequency because it did not affect the intersystem loss-of-coolant accident or steam generator tube rupture categories.

In addition, this finding had human performance cross-cutting aspects associated with decision-making, in that, the licensee failed to use conservative assumptions and verify the validity of the underlying assumptions [H.1(b)].

<u>Enforcement</u>. Title 10 CFR Part 50, Appendix B, Criteria XVI, "Corrective Action," requires, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, from October 2010 until August 2011, the licensee failed to establish measures to assure that conditions adverse to quality were promptly corrected. Specifically, the licensee failed to establish timely and adequate corrective actions to address a third wire that was potentially uninsulated, and could cause the control power fuse to blow, resulting in a loss of that train of equipment. Since this violation was of very low safety significance and was documented in the licensee's corrective action program as Condition Reports 11-13085 and 11-13422, it is being treated as a noncited violation consistent with Section 2.3.2. of the NRC Enforcement Policy: NCV 05000498/2011004-02 and 05000499/2011004-02, "Inadequate Corrective Actions from an Inadequate Extent of Condition Review."

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following postmaintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- July 8, 2011, Unit 1, ECW system train C through wall leak code repair
- July 14, 2011, Unit 1, centrifugal charging pump 1A design change to oil line connectors and inspection of motor bearings
- July 15, 2011, Unit 2, residual heat removal pump 2B disconnecting of motor cables to troubleshoot lowering insulation resistance
- July 19, 2011, Unit 2, steam generator power operated relief valve 2C hydraulic fluid replacement and gasket inspection
- July 21, 2011, Unit 1, SDG 13, replaced fuel pump and injector nozzle on cylinder 1R due to fuel oil leak
- August 22, 2011, Unit 2, unit auxiliary transformer load tap changer repairs following indications of arc strikes and dielectric fluid breakdown
- September 25, 2011, Unit 2, rod control shutdown bank C regulation and cycler card failures

The inspectors selected these activities based upon the structure, system, or component's ability to affect risk. The inspectors evaluated these activities for the following (as applicable):

- The effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed
- Acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate

The inspectors evaluated the activities against the technical specifications, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with postmaintenance tests to determine whether the licensee was identifying problems and entering them in the corrective action program and that the problems were being corrected commensurate with their importance to safety. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of seven postmaintenance testing inspection samples as defined in Inspection Procedure 71111.19-05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the UFSAR, procedure requirements, and technical specifications to ensure that the surveillance activities listed below demonstrated that the systems, structures, and/or components tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the significant surveillance test attributes were adequate to address the following:

- Preconditioning
- Evaluation of testing impact on the plant
- Acceptance criteria
- Test equipment
- Procedures
- Jumper/lifted lead controls
- Test data
- Testing frequency and method demonstrated technical specification operability
- Test equipment removal
- Restoration of plant systems
- Fulfillment of ASME Code requirements
- Updating of performance indicator data
- Engineering evaluations, root causes, and bases for returning tested systems, structures, and components not meeting the test acceptance criteria were correct
- Reference setting data
- Annunciators and alarms setpoints

The inspectors also verified that licensee personnel identified and implemented any needed corrective actions associated with the surveillance testing.

- July 1, 2011, Unit 1, steam generator power operated relief valve 1A inservice test
- July 6, 2011, Unit 1, AFW motor-driven pump 12 inservice test
- July 29, 2011, Unit 2, control rod operability test

Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of three surveillance testing inspection samples as defined in Inspection Procedure 71111.22-05.

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert Notification System Testing (71114.02)

a. Inspection Scope

The inspectors discussed with licensee staff the operability of offsite siren emergency warning systems and tone alert radio systems to determine the adequacy of licensee methods for testing the alert and notification system in accordance with 10 CFR Part 50, Appendix E. The licensee's alert and notification system testing program was compared with criteria in NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1; FEMA Report REP-10, "Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants," and the licensee's current FEMA-approved alert and notification system design report, "South Texas Project Electric Generating Station Updated Prompt Notification System Design Report," dated September 30, 2010. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.02-05.

b. Findings

No findings were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

a. Inspection Scope

The inspectors discussed with licensee staff the operability of primary and backup systems for augmenting the on-shift emergency response staff to determine the adequacy of licensee methods for staffing emergency response facilities in accordance with their emergency plan. The inspectors reviewed the documents and references listed in the attachment to this report to evaluate the licensee's ability to staff the emergency response facilities in accordance with the licensee's emergency plan and the requirements of 10 CFR Part 50, Appendix E. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.03-05.

b. Findings

No findings were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspectors reviewed summaries of 199 corrective action program documents assigned to the emergency preparedness department and emergency response organization between December 2009 and August 2011, and selected 33 for detailed review against the program requirements. The inspectors evaluated the response to the corrective action requests to determine the licensee's ability to identify, evaluate, and correct problems in accordance with the licensee program requirements, planning standard 10 CFR 50.47(b)(14), and 10 CFR Part 50, Appendix E. Specific documents reviewed during this inspection are listed in the attachment.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.05-05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on August 10, 2011, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator, technical support center, operations support center, and the incident command post to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the corrective action program. As part of the inspection, the inspectors reviewed the drill package.

These activities constitute completion of one sample as defined in Inspection Procedure 71114.06-05.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the performance indicator data submitted by the licensee for the second quarter 2011 performance indicators for any obvious inconsistencies prior to its public release in accordance with Inspection Manual Chapter 0608, "Performance Indicator Program."

This review was performed as part of the inspectors' normal plant status activities and, as such, did not constitute a separate inspection sample.

b. Findings

No findings were identified.

.2 Safety System Functional Failures (MS05)

a. Inspection Scope

The inspectors sampled licensee submittals for the safety system functional failures performance indicator for Units 1 and 2 for the period from the third quarter 2010 through the second quarter 2011. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, and NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73." The inspectors reviewed the licensee's operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, issue reports, event reports, and NRC integrated inspection reports for the period of July 2010 through June 2011 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed during this inspection are described in the attachment.

These activities constitute completion of one safety system functional failures sample per unit as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.3 Reactor Coolant System Specific Activity (BI01)

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system specific activity performance indicator for Units 1 and 2 for the period from the third quarter 2010 through the second quarter 2011. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's reactor coolant system chemistry samples, technical specification requirements, issue reports, event reports, and NRC integrated inspection reports for the period of July 2010 through June 2011 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. In addition to record reviews, the inspectors observed a chemistry technician obtain and analyze a reactor coolant system sample. Specific documents reviewed during this inspection are described in the attachment.

These activities constitute completion of one reactor coolant system specific activity sample per unit as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.4 Reactor Coolant System Leakage (BI02)

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system leakage performance indicator for Units 1 and 2 for the period from the third quarter 2010 through the second quarter 2011. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's operator logs; reactor coolant system leakage tracking data, issue reports, event reports, and NRC integrated inspection reports for the period of July 2010 through June 2011 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the performance indicator data collected or transmitted for this indicator and none were identified. Specific documents reviewed during this inspection are described in the attachment.

These activities constitute completion of one reactor coolant system leakage sample per unit as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.5 Drill/Exercise Performance (EP01)

a. Inspection Scope

The inspectors sampled licensee submittals for the drill and exercise performance indicator for the period from the third quarter 2010 through the second quarter 2011. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the performance indicator; assessments of performance indicator opportunities during predesignated control room simulator training sessions; performance during the 2010 biennial exercise; and performance during other drills. Specific documents reviewed during this inspection are described in the attachment.

These activities constitute completion of the drill/exercise performance sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.6 Emergency Response Organization Drill Participation (EP02)

a. Inspection Scope

The inspectors sampled licensee submittals for the emergency response organization drill participation performance indicator for the period from the third quarter 2010 through the second quarter 2011. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the performance indicator; rosters of personnel assigned to key emergency response organization positions; and exercise participation records. Specific documents reviewed during this inspection are described in the attachment.

These activities constitute completion of the emergency response organization drill participation sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

.7 Alert and Notification System (EP03)

a. Inspection Scope

The inspectors sampled licensee submittals for the alert and notification system performance indicator for the period from the third quarter 2010 through the second quarter 2011. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in NEI Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6. The inspectors reviewed the licensee’s records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the performance indicator; and the results of periodic alert notification system operability tests. Specific documents reviewed during this inspection are described in the attachment.

These activities constitute completion of the alert and notification system sample as defined in Inspection Procedure 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action program at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. The inspectors reviewed attributes that included the complete and accurate identification of the problem; the timely correction, commensurate with the safety significance; the evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent of condition reviews, and previous occurrences reviews; and the classification, prioritization, focus, and timeliness of corrective actions. Minor issues entered into the licensee's corrective action program because of the inspectors' observations are included in the attached list of documents reviewed.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure, they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. The inspectors accomplished this through review of the station's daily corrective action documents.

The inspectors performed these daily reviews as part of their daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

.3 Selected Issue Follow-up Inspection

a. Inspection Scope

During a review of items entered in the licensee's corrective action program, the inspectors recognized a corrective action item documenting the voltage on the Unit 2 safety-related 480 Vac buses being high out of band per the surveillance procedure. Over the course of the inspection period, the licensee documented several occurrences where the voltage exceeded the surveillance procedure criteria. The licensee was already in the process of performing a prompt operability determination, a reportability review, and a root cause investigation to understand the sequence of events that resulted in an inadequate design change package being implemented on the Units 1 and 2 ESF train B 4160 Vac transformers and setpoint changes on the Units 1 and 2 unit auxiliary transformers. The inspectors, along with regional inspectors, reviewed all the condition reports generated, the UFSAR, technical specifications, design basis documents, the design change package, the root cause investigation, the operability determination, compensatory measures, station logs, vendor documents, and interviewed personnel. The inspectors focused on verifying that the licensee had appropriately evaluated all of the electrical components for operability to ensure they were still able to perform their safety-related functions. This included any compensatory measures that were in place to prevent the bus voltage from exceeding the surveillance procedure criteria.

These activities constitute completion of one in-depth problem identification and resolution sample as defined in Inspection Procedure 71152-05.

b. Findings

Introduction. The inspectors identified a Green noncited violation of 10 CFR Part 50, Appendix B, Criteria XVI, “Corrective Action,” for the failure to assure that conditions adverse to quality were promptly identified and corrected.

Description. In October 2009, during the Unit 1 Refueling Outage, and in April 2010, during the Unit 2 Refueling Outage, the licensee installed new train B 4160 Vac ESF transformers. The new transformers have a load tap changer feature that the old transformers did not have. The design change package installed new control switches in the control room for manual operation of the load tap changer. However, the design change package did not specify that a procedure was needed to allow the operators to control the load tap changer in manual if the need arose. When questioned by the residents during the October 2009 timeframe, the response was that the operators would not be required to take manual control of the load tap changer; it was expected to work in automatic. The inspectors reviewed the training material presented to operations as well as the design change package and the procedure requests associated with the modification and continued to question the licensee.

During the Unit 2 replacement in April 2010, the inspectors again asked the question about how was operations supposed to manipulate the load tap changer if they do not have training or procedures for manual control. In December 2010, Unit 2 experienced a material issue with the load tap changer and was required to place the load tap changer in manual. However, since they had no procedure on how to operate it, they had to develop a standing order to allow for operations to control the load tap changer in manual while a condition report engineering evaluation and condition report operations evaluation were performed that gave them procedural guidance on how to operate the load tap changer in manual. This condition report operations evaluation was never proceduralized, and was only applicable to Unit 2. In addition, it was only in effect for the current condition and expired when they restored from the maintenance state.

In May 2011, the licensee experienced another material condition issue with the Unit 2 load tap changer that required operations to place the load tap changer in manual. However because the procedure was never changed, and the condition report operations evaluation had expired, operations found themselves operating the plant outside of procedural guidance, again. Corrective actions included revising Procedure 0POP02-AE-0002, "Transformer Normal Breaker and Switch Lineup," Revision 33, to include manual operation of the train B 4160 Vac ESF transformers load tap changers for both units, and training all the operations personnel on the new procedure.

Analysis. The failure to promptly identify and correct a condition adverse to quality that affected all the train B safety-related equipment was a performance deficiency. This finding was more than minor because it was associated with the Mitigating Systems Cornerstone attributes of Design Control and Procedure Quality, and it affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The deficiency resulted in operations not having guidance on how to control the Units 1 and 2 train B 4160 Vac transformer load tap changer to ensure that the bus remained within technical specification surveillance requirement voltage limits. The inspectors performed the significance determination using NRC Inspection Manual Chapter 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," dated January 10, 2008, because it affected the Mitigating Systems Cornerstone while the plant was at power. The finding was determined to be of very low safety significance (Green) because it was not a design or qualification deficiency; it did not represent a loss of safety system function; it did not represent the loss of a single train for greater than technical specification allowed outage time; it did not represent a loss of one or more nontechnical specification risk-significant equipment for greater than 24 hours; and it did not screen as potentially risk significant due to seismic, flooding, or severe weather. In addition, this finding had human performance cross-cutting aspects associated with decision making, in that, the licensee failed to communicate decisions and the basis for decisions to personnel who have a need to know the information to perform work safely [H.1(c)].

Enforcement. Title 10 CFR Part 50, Appendix B, Criteria XVI, "Corrective Action," requires, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, from October 2009 until May 2011, the licensee failed to establish measures to assure that conditions adverse to quality were promptly corrected. Specifically, the licensee failed to establish timely and adequate corrective actions to address manual operation of the newly installed train B 4160 Vac ESF transformers load tap changers; this resulted in the safety-related loads supplied by the transformer being outside the surveillance procedure limit. Since this violation was of very low safety significance and was documented in the licensee's corrective action program as Condition Report 11-8545, it is being treated as a noncited violation consistent with Section 2.3.2 of the NRC Enforcement Policy: NCV 05000498/2011004-03 and 05000499/2011004-03, "Untimely Corrective Action to Correct an Inadequate Procedure."

4OA3 Event Follow-up (71153)

(Closed) Licensee Event Report 05000499/2010-006-00, "Technical Specifications Not Met for Reactor Coolant System Unidentified Leakage"

The licensee submitted this event report in accordance with 10 CFR 50.73(a)(2)(i)(B), any operation or condition prohibited by the plant's technical specifications. On November 10, 2010, at 9:10 a.m., Unit 2 was in Mode 3 at normal operating pressure and temperature; reactor operators were preparing to transition to Mode 2 when they identified a lowering trend in volume control tank level and an increased frequency of reactor water makeup. The crew entered Technical Specification 3.4.6.2, Action b, for unidentified reactor coolant system leakage greater than 1.0 gallons per minute. The crew calculated the leakage to be about 2.0 gallons per minute. Subsequent investigation to determine the source of the leakage identified that reactor coolant filter 2B vent valve 2-CV-0142A was leaking. The valve stem nut on the remote operator was found broken resulting in the failure of the valve to close. The 2B filter was isolated and removed from service which stopped the leakage at 3:31 p.m. Further review, by engineering staff, identified the leakage began at 12:25 p.m. on November 5, 2010, following the replacement of the 2B filter, when Unit 2 was in Mode 5 and Technical Specification 3.4.6.2 did not apply. Unit 2 entered Mode 4 at 11:48 p.m. on November 8, 2010, and Mode 3 at 2:53 a.m. on November 9, 2010. Technical Specification 3.4.6.2 applies in Modes 1 through 4. Therefore, the licensee operated in Mode 4 and Mode 3 for 39 hours and 43 minutes before the unidentified leakage was stopped. In addition, the licensee transitioned into these modes with leakage greater than allowed by technical specifications, which is not allowed by Technical Specification 3.0.4. The inspectors interviewed personnel and reviewed the root cause investigation. The inspectors determined that the licensee violated Technical Specification 3.0.4 by transitioning into Mode 4 and Mode 3 with unidentified leakage greater than 1.0 gallons per minute and stayed in these modes longer than 34 hours, which was the allowed time to be in Mode 5 if the leakage could not be reduced within limits. The enforcement aspects of this event are described in Section 4OA7. This licensee event report is closed.

4OA5 Other Activities

(Closed) Unresolved Item 05000498/2010007-03, 05000499/2010007-03, "Transfer of Station Blackout Requirements from Current Licensing Basis into Final Safety Analysis Report"

In 2010, the Component Design Basis Inspection Team identified Unresolved Item 05000498/2010007-03, 050000499/2010007-03, "Transfer Station Blackout Requirements from Current Licensing Basis into Final Safety Analysis Report." Specifically, the team questioned why the licensee's Surveillance Test 32345357, "125 Volt Class 1E Battery Modified Performance Surveillance Test," discharge time was terminated after 3 hours and 26 minutes for the 125 Vdc batteries even though: 1) the current licensing basis specified a 4-hour duty cycle, and 2) that the licensee had never tested their batteries to the established station blackout design requirements (battery duty cycle). Additionally, the team questioned whether the licensee was approved to be an alternate ac power plant with or without a coping analysis. To resolve this matter, the team was waiting on the licensee's clarification of their position. To clarify their current licensing basis of record, the licensee revised their station blackout position to delete the need for a coping analysis. This UFSAR revision did not change the analysis or basis for the previously established conclusion, and after reviewing the Licensing Basis Document Change Request 0PGP05-ZN-004, "Revise Station Blackout Position to delete the need for a Coping Analysis," dated March 30, 2011, the team determined that this unresolved item can be closed, and that the licensee's surveillance testing was acceptable.

4OA6 Meetings

Exit Meeting Summary

On September 22, 2011, the inspectors presented the onsite emergency preparedness inspection results to Mr. D. Rencurrel, Senior Vice President, Units 1 and 2, and other members of the licensee's staff. The licensee's management acknowledged the issues presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On October 6, 2011, the residents presented the results of the unresolved item closeout inspection as part of their routine quarterly exit to Mr. M. Meier, Vice President and Assistant to the President and Chief Executive Officer, and other members of the licensee staff. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On October 6, 2011, the inspectors presented the inspection results to Mr. M. Meier, Vice President and Assistant to the President and Chief Executive Officer, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section 2.3.2 of the NRC Enforcement Policy for being dispositioned as noncited violations.

- Technical Specification 3.0.4 requires, in part, that when a limiting condition for operation is not met, entry into a mode shall only be made when the associated actions permit continued operation in the mode for an unlimited period of time, or after performance of a risk assessment and establishment of risk management actions. In addition, Technical Specification 3.4.6.2 requires, in part, that while the plant is operating in Modes 1 through 4, unidentified reactor coolant system leakage shall be limited to 1.0 gallons per minute, and identified leakage shall be limited to 10.0 gallons per minute, or reduce to within limits within 4 hours, or be in Mode 3 within 6 hours and Mode 5 within the next 30 hours. Contrary to the above, the licensee failed to meet the requirements of Technical Specification 3.0.4, because Unit 2 entered Mode 4 on November 8, 2010, and Mode 3 on November 9, 2010, with unidentified leakage at approximately 2.0 gallons per minute, without reducing the leakage to within limits or transitioning to Mode 5 within the required timeframe; nor did they perform the required risk assessment or implement any risk management actions prior to making the mode changes. This violation was processed through significance determination process using Manual Chapter 0609, Appendix A, because the licensee had secured from using residual heat removal system in Mode 3. The finding was determined to be of very low safety significance because, assuming the worst case degradation, the finding would not have resulted in exceeding the 10 gallons per minute technical specification limit for reactor coolant system for identified leakage. The licensee entered this issue into their corrective action program as Condition Report 10-24488.

- Technical Specification 6.8.1.a requires the licensee to implement the procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, dated February 1978. Regulatory Guide 1.33, Appendix A, Section 9, Procedures for Performing Maintenance, Part a states, in part, that maintenance that can affect the performance of safety-related equipment should be properly performed in accordance with written procedures. Procedure 0PMP02-NZ-0013, “Cable Terminations,” specifies how the licensee is to terminate unused cables to prevent damage to equipment. Contrary to the above, from February 2005 to March 2011, the licensee failed to correctly terminate the replacement Static-O-Ring temperature switch for one of the Unit 2 ECW train A vent fans. The finding was determined to be of very low safety significance because only one train of ECW was inoperable for less than the technical specification allowed outage time. The licensee entered this issue into the corrective action program as as Condition Report 10-23446.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

R. Aguilera, Manager, Health Physics
M. Berg, Manager, Design Engineering
C. Bowman, General Manager, Nuclear Safety Assurance
J. Calvert, Manager, Training
R. Dunn Jr., Manager, Fuels and Analysis
R. Engen, Site Engineering Director
J. Enoch, Supervisor, Emergency Preparedness
T. Frawley, Manager, Operations
W. Harrison, Manager, Licensing
J. Hartley, Manager, Mechanical Maintenance
G. Hildebrandt, Manager, Plant Protection
S. Horak, Emergency Preparedness
G. Janak, Manager, Unit 1 Operations
B. Jenewein, Manager, Systems Engineering
M. Keyes, Emergency Preparedness
S. Korenek, Emergency Preparedness
J. Lovejoy, Manager, I&C Maintenance
J. Loya, Engineer, Licensing Staff
G. MacDonald, Manager, Organizational Effectiveness
R. McNiel, Manager, Maintenance Engineering
M. Meier, Vice President and Assistant to the Chief Executive Officer
J. Milliff, Manager, Unit 2 Operations
M. Oswald, Supervising Engineer
J. Paul, Engineer, Licensing Consultant
L. Peter, Plant General Manager
J. Pierce, Manager, Operations Training
G. Powell, Vice President, Generation
D. Rencurrel, Vice President, Technical Support and Oversight
K. Richards, Senior Vice President
M. Ruvalcaba, Manager, Testing and Programs
R. Savage, Engineer, Licensing Staff Specialist
M. Schaefer, Manager, Maintenance
S. Sovizral, Manager, Security Operations
K. Taplett, Senior Engineer, Licensing Staff
D. Zink, Supervising Engineering Specialist

NRC Personnel

J. Dixon, Senior Resident Inspector
B. Tharakan, Resident Inspector

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000498/2011004-01	NCV	Failure to Follow Standby Diesel Generator Maintenance Procedures (Section 1R15)
05000498/2011004-02 05000499/2011004-02	NCV	Inadequate Corrective Actions from an Inadequate Extent of Condition Review (Section 1R15)
05000498/2011004-03 05000499/2011004-03	NCV	Untimely Corrective Action to Correct an Inadequate Procedure (Section 4OA2)

Closed

05000499/2010-006-00	LER	Technical Specifications Not Met for Reactor Coolant System Unidentified Leakage (Section 4OA3)
05000498/2010007-03 05000499/2010007-03	URI	Transfer of Station Blackout Requirements from Current Licensing Basis into Final Safety Analysis Report (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

PROCEDURES

NUMBER	TITLE	REVISION
0PSP03-ZQ-0028	Operator Logs for 'D' Train Isolation Valve Cubicle Temperature	115

Section 1R04: Equipment Alignment

CONDITION REPORTS

06-3458	11-12309

DRAWINGS

NUMBER	TITLE	REVISION
5R209F05017#2	Piping and Instrumentation Diagram Component Cooling Water System	20
5R209F05018#2	Piping and Instrumentation Diagram Component Cooling Water System	19
5R209F05020#2	Piping and Instrumentation Diagram Component Cooling Water System	16
5R289F05038 #2	Piping and Instrumentation Drawing Essential Cooling Water System Train 2B	12

PROCEDURES

NUMBER	TITLE	REVISION
0POP02-CC-0001	Component Cooling Water	40
0POP02-EW-0001	Essential Cooling Water Operations	57

Section 1R05: Fire Protection

CONDITION REPORTS

11-9447	11-12004	11-18328
11-11950	11-18274	

FIRE PREPLANS

NUMBER	TITLE	REVISION
0IVC48-FP-0406	Isolation Valve Cubicle Penetration Area Train C	3
0IVC49-FP-0402	Isolation Valve Cubicle Pump Room Train B	3
0IVC49-FP-0407	Isolation Valve Cubicle Penetration Area Train B	3

PROCEDURES

NUMBER	TITLE	REVISION
0PGP03-ZA-0514	Controlled System or Barrier Impairment	8
0PGP03-ZF-0001	Fire Protection Program	23
0PGP03-ZF-0018	Fire Protection System Functionality Requirements	16

NUMBER	TITLE	REVISION
0PGP03-ZF-0019	Control of Transient Fire Loads and Use of Combustible and Flammable Liquids and Gases	7
0PTP03-FP-117	Hose Station Visual Inspection	6
0PTP03-FP-119	Fire Hose Station Valves Functionality Tests	6
0PTP03-FP-120	Fire Hose Hydrostatic Test	9

WORK AUTHORIZATION NUMBERS

375790

Section 1R11: Licensed Operator Requalification Program

MISCELLANEOUS

NUMBER	TITLE	REVISION
LOR105	Licensed Operator Requalification 2010 Annual Performance Test Exam 8	0

Section 1R12: Maintenance Effectiveness

CONDITION REPORTS

04-2848	10-9239	11-5936
04-10648	10-20713	11-6774
04-10651	10-23832	11-9768
07-9459		

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
5A050GAEH01	Risk Significance Basis Document Electro-hydraulic (EH) Control System	5
5A050GAPG01	Risk Significance Basis Document 13.8 kVac Emergency Power (PG) System	1
MG-006	Work Execution and Closeout Guideline	9
System Health Report	Main Steam System Health Report	Fourth Quarter 2010
System Health Report	13.8-4.16 kVac Non-class 1E (PC, PD, PG)	Fourth Quarter 2009-Second Quarter 2011

NUMBER	TITLE	REVISION/DATE
System Health Report	Electro-hydraulic Controls	Third Quarter 2009-Second Quarter 2011
	Maintenance Rule Expert Panel Meeting Minutes	September 8, 2010
	Maintenance Rule Scoping Basis Report	September 8, 2010

PROCEDURES

NUMBER	TITLE	REVISION
0PGP02-ZA-0003	Comprehensive Risk Management Program	13
0PGP02-ZA-0062	Integrated Working Group Process	1
0PMP04-SG-0007	Steam Generator PORV Hydraulic Actuator Maintenance	19

Section 1R13: Maintenance Risk Assessment and Emergent Work Controls

CONDITION REPORTS

11-11523	11-11811	11-14081
11-11648	11-11826	11-15930
11-11651	11-12008	11-15934
11-11810	11-13304	11-17675

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
	Daily STP RAsCal Calculations for Units 1 and 2	September 5-9, 2011
	Daily STP RAsCal Calculations for Units 1 and 2	September 19-24, 2011
2274	Work Activity Risk Plan of Action	0, 1
2282	Work Activity Risk Plan of Action	0

PROCEDURES

NUMBER	TITLE	REVISION
0PGP03-XS-0001	Switchyard Management	1
0PGP03-ZA-0090	Work Process Program	36
0PGP03-ZA-0091	Configuration Risk Management Program	11
0PGP03-ZO-0055	Protected Components	0
0POP01-ZO-0006	Risk Management Actions (RMAs)	18
0PSP03-EA-0002	ESF Power Availability	27
0PSP03-ZQ-0028	Operator Logs	115

Section 1R15: Operability Evaluations

CONDITION REPORTS

04-11502	11-11588	11-13883
10-25564	11-11651	11-13949
11-8545	11-11810	11-16079
11-9861	11-12322	11-16670
11-10205	11-12872	11-18783
11-10521		

WORK AUTHORIZATION NUMBERS

416904	426665
426544	427292

MISCELLANEOUS

NUMBER	TITLE	DATE
	Electrical Design Basis Margin Recovery Team	September 21, 2011
NSAL 11-3	Westinghouse Nuclear Safety Advisory Letter 11-3: Post Accident Monitoring System Replacement Power Supply Cable Harness	July 13, 2011

PROCEDURES

NUMBER	TITLE	REVISION
0PGP03-HU-0001	Human Performance (HU) Program	0
0PGP03-ZX-0013	Operating Experience Program	9
0PGP04-ZA-0108	Vendor Document Control Program	8
0PSP03-ZQ-0028	Operator Logs	115
0PSP03-DG-0003	Standby Diesel Generator 13(23) Operability Test	43
WCG-0002	Work Management Scheduling	24
WCG-0003	Work Planner’s Guide	28
MG-0006	Work Execution and Closeout Guideline	9
0OOI01-OL-0005	Operator Logs – Diesel Generator	15

Section 1R19: Postmaintenance Testing

CONDITION REPORTS

94-2525	10-8717	11-11950
04-11992	11-8615	11-12769
04-13449	11-11096	11-13304
06-4207	11-11588	11-17675

PROCEDURES

NUMBER	TITLE	REVISION
0PGP03-ZM-0025A	Post-Maintenance Testing Implementation	1
0PMP05-RH-0001	Residual Heat Removal Pump Motor Inspection	8
0PMP05-ZE-0202	Insulation Resistance Testing - Low Voltage Motors	18
0PSP03-DG-0003	Standby Diesel 13(23) Operability Test	43
0PSP03-MS-0001	Main Steam System Valve Operability Test	34
0PSP03-RH-0002	Residual Heat Removal Pump 1B(2B) Inservice Test	15
0PSP03-RS-0001	Monthly Control Rod Operability	30
0PSP03-RS-0003	Control Rod Operability (Single Rod)	2

WORK AUTHORIZATION NUMBERS

386406	418188	426665
407472	423179	428225
407475	426072	430551
410670	426544	

Section 1R22: Surveillance Testing

CONDITION REPORTS

11-10783

PROCEDURES

NUMBER	TITLE	REVISION
5S109MB01026	Main Steam System	4
0PGP03-ZE-0021	Inservice Testing Program for Valves	18
0PMP04-SG-0007	Steam Generator PORV Hydraulic Actuator Maintenance	19
0PSP03-AF-0002	Auxiliary Feedwater Pump 12(22) Inservice Test	32
0PSP03-MS-0001	Main Steam System Valve Operability Test	34
0PSP03-RS-0001	Monthly Control Rod Operability Test	30
0PSP05-MS-7411L	Steam Generator Header Pressure Loop Calibration	22

WORK AUTHORIZATION NUMBERS

383296	415814	422794
391371		

Section 1EP2: Alert Notification System Testing

MISCELLANEOUS

TITLE	DATE
South Texas Project Electric Generating Station Updated Prompt Notification System Design Report	September 30, 2010

PROCEDURES

NUMBER	TITLE	REVISION
0PGP05-ZV-0007	Prompt Notification System	9
0PGP05-ZV-0016	Prompt Notification System Implementing Procedure	8

Section 1EP3: Emergency Response Organization Augmentation Testing

MISCELLANEOUS

TITLE	DATE
Emergency Notification and Response System Test, 2nd Qtr 2010, 3rd Qtr 2010, 4th Qtr 2010, 1st Qtr 2011, 2nd Qtr 2011, and 3rd Qtr 2011	
Six Year Off-hours Call-out	January 27, 2010

Section 1EP5: Correction of Emergency Preparedness Weaknesses and Deficiencies

CONDITION REPORTS

09-20394	10-12483	10-20313
10-00799	10-12485	10-23390
10-01590	10-12486	10-23533
10-01622	10-12487	10-23537
10-02982	10-12488	10-23777
10-12086	10-13078	10-24085
10-12478	10-13460	10-26793
10-12479	10-15933	11-05737
10-12480	10-15934	11-13001
10-12481	10-16550	11-17814
10-12482	10-17643	

MISCELLANEOUS

NUMBER	TITLE	REVISION/DATE
10-01(EP)	Emergency Preparedness Quality Audit Report	March 11, 2010
11-01(EP)	Emergency Preparedness Quality Audit Report	March 15, 2011

NUMBER	TITLE	REVISION/DATE
	Red Team Combined Functional Drill	January 27, 2010
	Red Team Combined Functional Drill	March 2, 2011
	White Team Combined Functional Drill	July 20, 2010
	White Team Dress Rehearsal	September 1, 2010
	White Team Graded Exercise	October 27, 2010
	White Team Combined Functional Drill	June 22, 2011
	Blue Team Combined Functional Drill	May 26, 2010
	Blue Team Combined Functional Drill	August 10, 2011
	STP Health Physics Liquid Sample Mini Drill	December 3. 2009
	STP Health Physics Liquid Sample Mini Drill	December 14, 2010
	2009 Field Monitoring Drill	December 3, 2009
	2010 Field Monitoring Drill	November 11, 2010
	South Texas Project Emergency Plan	ICN 20-10

PROCEDURES

NUMBER	TITLE	REVISION
0PGP03-ZT-0139	Emergency Preparedness Training Program	16
0PGP05-ZV-0014	Emergency Response Activities	10

Section 4OA1: Performance Indicator Verification

MISCELLANEOUS

NUMBER	TITLE	REVISION
AD-0007	Collection of NRC Performance Indicator Data - Reactor Coolant System Specific Activity	1, 2, 3
LDG-01	Licensing Department Desktop Guideline NRC Performance Indicator: Safety System Functional Failures	0
LDG-01	NRC Performance Indicator: Safety System Functional Failures	1
PI-0002	NRC Performance Indicator: Initiating Events Cornerstone (by Unit) and Barrier Integrity Cornerstone (by Unit) Desktop Guidelines	2
PI-0002	NRC & INPO Performance Indicator: Initiating Events Cornerstone (by Unit) and Barrier Integrity Cornerstone (by Unit) Desktop Guidelines	3

PROCEDURES

NUMBER	TITLE	REVISION
0PSP07-ZQ-0001	Weekly Chemistry Surveillance Logs	15, 16

Section 4OA2: Identification and Resolution of Problems

CONDITION REPORTS

04-11502	11-10205	11-11811
10-25564	11-10521	11-13883
11-8545	11-11073	11-13949
11-8790	11-11651	11-16670
11-9861	11-11810	

PROCEDURES

NUMBER	TITLE	REVISION
0POP02-AE-0002	Transformer Normal Breaker and Switch Lineup	33
0PSP03-ZQ-0028	Operator Logs	115

Section 4OA3: Event Follow-Up

CONDITION REPORTS

10-24488

Section 4OA5: Other Activities

CONDITION REPORTS

10-25816

MISCELLANEOUS

NUMBER	TITLE	DATE
10-17753-5	Revise Station Blackout Position to delete the need for a Coping Analysis	March 30, 2011

Section 4OA7: Licensee-Identified Violations

CONDITION REPORTS

10-17093	10-24488	11-13085
10-23446		

PROCEDURES

NUMBER	TITLE	REVISION
0PMP02-NZ-0013	Cable Terminations	16, 21
0POP03-ZG-0001	Plant Heatup	54
0PSP03-RC-0006	Reactor Coolant Inventory	21