UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

November 14, 2007

James J. Sheppard, President and
Chief Executive Officer
STP Nuclear Operating Company
P.O. Box 289
Wadsworth, TX 77483

SUBJECT: SOUTH TEXAS PROJECT ELECTRIC GENERATING STATION - NRC INTEGRATION INSPECTION REPORT 05000498/2007004 AND 05000499/2007004

Dear Mr. Sheppard:

On October 5, 2007, 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 report documents the inspection findings, which were discussed on October 11, 2007, with Mr. E. Halpin and other members of your staff.

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

Based on the results of this inspection, two self-revealing findings of very low safety significance (Green) were identified, one of which was determined to be a violation. In addition, a licensee-identified violation, which was determined to be of very low safety significance, is listed in Section 4OA7 of this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these violations as noncited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest 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 DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at South Texas Project Electric Generating Station, Units 1 and 2, 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 any) will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Claude E. Johnson, Chief
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Dockets: 50-498
50-499
Licenses: NPF-76
NPF-80

Enclosure:
NRC Inspection Report 05000498/2007004 and 05000499/2007004
w/Attachment: Supplemental Information

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Regional State Liaison Officer **(WAM)**
NSIR/DPR/EPD **(JTJ1)**
STP Site Secretary (HLW1)

SUNSI Review Completed: _CEJ__ ADAMS: √ Yes No Initials: ___CEJ___
√ Publicly Available ☐ Non-Publicly Available ☐ Sensitive √ Non-Sensitive

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RIV:SRI:DRP/A	C:DRS/PSB	C:DRS/EB	C:DRS/OB	C:DRS/PEB
JLDixon	MPShannon	WBJones	ATGody	LJSmith
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U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	05000498, 05000499
Licenses:	NPF-76, NPF-80
Report:	05000498/2007004 and 05000499/2007004
Licensee:	STP Nuclear Operating Company
Facility:	South Texas Project Electric Generating Station, Units 1 and 2
Location:	FM 521 - 8 miles west of Wadsworth Wadsworth, Texas 77483
Dates:	July 7 through October 5, 2007
Inspectors:	J. Dixon, Senior Resident Inspector P. J. Elkmann, Emergency Preparedness Inspector P. A. Goldberg, P.E., Reactor Inspector, EB2 M. Haire, Senior Operations Engineer
Approved By:	Claude E. Johnson, Chief, Project Branch A Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000498/2007004, 05000499/2007004; 07/07/07 - 10/05/07; South Texas Project Electric Generating Station, Units 1 and 2; Integrated Resident and Regional Report; Maintenance Risk Assessments and Emergent Work Control, Other Activities.

This report covered a 3-month period of inspection by resident and regional inspectors. The inspection identified two Green findings. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management's review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors reviewed a self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criteria V, "Instructions, Procedures, and Drawings," for an inadequate surveillance test procedure on the turbine-driven auxiliary feedwater pump, due to inadequate acceptance criteria for the trip hook and the latch-up lever and the impact distance. As a result, on December 12, 2006, auxiliary feedwater Pump 14 failed to reach rated speed and tripped.

  The inspectors determined that the issue was more than minor because it affected the mitigating systems cornerstone attributes of equipment performance and procedure quality, and it affected the cornerstone objective to ensure the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. The inspectors evaluated the violation using the significance determination process and determined that it required a Phase 2 analysis. The Phase 2 analysis screened as White and the resultant Phase 3 SPAR model result was an incremental conditional core damage probability of 3E-07. The licensee's Phase 3 analysis gives recovery credit for manual operator action to locally start the turbine-driven pump and resulted in a probability of 3.3E-07, or very low safety significance. This issue had problem identification and resolution crosscutting aspects in that the licensee did not implement and institutionalize operating experience through changes to procedures and training programs [P.2(b)]. The licensee failed to fully evaluate specific operating experience to conclude that the maintenance, surveillance, and operating procedures were inadequate to ensure consistent, repeatable, and reliable measurements to critical components. This lack of fully implementing and institutionalizing operating experience directly contributed to the event (Section 4OA5).

Cornerstone: Miscellaneous

- Green. The inspectors reviewed a self-revealing finding for an inadequate procedure, STI 32174927, "Conduct of Maintenance," Revision 5, for work associated with the Unit 1 emergency response facility data acquisition and display systems inverter modification activities. On August 27, 2007, maintenance personnel were installing a 4-inch diameter conduit in the Unit 1 Train B 4160 volt switchgear room in close proximity to a voltage regulating transformer which was powering Distribution Panels DP 200 and DP 300, which powers approximately 25 percent of the control room annunciators. While installing the conduit, it came into contact with the input breaker on the transformer causing it to open and de-energized Distribution Panels DP 200 and DP 300. All loads lost were recovered in approximately 30 minutes with no additional challenges. As a result of this lack of procedural guidance for working around sensitive equipment, the crews' prejob and at the work site briefs did not recognize the potential impact of working in close proximity to the transformer powering Distribution Panels DP 200 and DP 300.

  The failure to adequately control the conduit being installed, as a result of inadequate procedural guidance and which resulted in 25 percent of control room annunciators being lost, was considered a performance deficiency. This finding was more than minor because it could impact the operator's ability to respond to unusual plant conditions due to lack of control room annunciators, and the reliance on reports from operators in the field; and if left uncorrected, this type of control room deficiency could become a more significant safety concern. The inspectors evaluated the significance of this finding using Inspection Manual Chapter 0609, Appendix M, "Significance Determination Process using Qualitative Criteria," and determined that the finding was of very low safety significance based on the fact that the loss of annunciators did not challenge the ability to determine emergency action levels, was of short duration, did not impact any automatic actuation systems, and the operations crew took immediate corrective and compensatory actions to restore the transformer. This finding had a crosscutting aspect in the area of human performance associated with the work control component because the licensee failed to ensure that adequate guidance was available to properly evaluate specific job site conditions, and the potential for human-system interface [H.3(a)] with regard to sensitive equipment. This directly contributed to the event because the workers were unaware of how their activities could have an impact on sensitive equipment (Section 1R13).

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent rated thermal power (RTP) and operated at or near full RTP for the remainder of the inspection period.

Unit 2 began the inspection period at 100 percent RTP. On August 5, 2007, the unit experienced a power failure to a fieldbus which resulted in the loss of two heater drip pumps and two low pressure heater strings necessitating a down power to approximately 45 percent RTP. The unit achieved 100 percent RTP on August 6, 2007, and operated at or near full RTP for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

Readiness for Seasonal Susceptibilities

a. Inspection Scope

The inspectors completed a review of the licensee's readiness of seasonal susceptibilities involving high temperatures. The inspectors: (1) reviewed plant procedures, the Updated Final Safety Analysis Report (UFSAR), Technical Specifications (TSs), and the Technical Requirements Manual to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of the systems listed below to ensure that adverse weather protection features (heat tracing, space heaters, weatherized enclosures, temporary chillers, etc.) were sufficient to support operability including the ability to perform safe shutdown functions; (3) evaluated operator staffing levels to ensure the licensee could maintain the readiness of essential systems required by plant procedures; and (4) reviewed the corrective action program (CAP) to determine if the licensee identified and corrected problems related to adverse weather conditions.

- August 24, 2007, Units 1 and 2, auxiliary engineered safety feature transformers Trains A, B, and C and auxiliary feedwater (AFW) Pumps A, B, C, and D cubicles

Documents reviewed by the inspectors included:

- Procedure 0PGP03-ZV-0001, “Severe Weather Plan,” Revision 13

- Procedure 0POP09-AN-22M1, "Annunciator Lampbox 22M01 Response Instructions," Revision 16

- Condition reports (CRs) 05-3384, 05-8880, and 07-12053

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

Partial Walkdown

a. Inspection Scope

The inspectors: (1) walked down portions of the three below listed risk important systems and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned, and (2) compared deficiencies identified during the walk down to the licensee's UFSAR and CAP to ensure problems were being identified and corrected.

- September 7, 2007, Unit 1, essential Chiller 12A and essential chilled water Train A due to emergent maintenance as a result of air inleakage into the chiller

- September 18, 2007, Unit 2, essential cooling water (ECW) Train C due to identification of dealloying of an aluminum bronze valve seat

- September 27, 2007, Unit 1, AFW Train A due to anti-rotation pin replacement on the outboard bearing on AFW Pump 11

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

Quarterly Inspection

a. Inspection Scope

The inspectors walked down the six below listed plant areas to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional and that access to manual actuators was unobstructed; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features and that the compensatory measures were commensurate with the significance of the deficiency; and (7) reviewed the UFSAR to determine if the licensee identified and corrected fire protection problems.

- July 17, 2007, Unit 1, Standby Diesel Generator (SDG) 12 areas (Fire Zones Z501 and Z507)
- August 8, 2007, Unit 1, electrical auxiliary building engineered safety feature switchgear Train B and Channel III battery and distribution rooms (Fire Zones Z042 and Z043)
- August 17, 2007, Unit 1, main control room, shift supervisor's office, and relay cabinet area of control room (Fire Zones Z032, Z034, and Z083)
- August 20, 2007, Unit 2, component cooling water (CCW) pump and essential chiller Train A and mechanical auxiliary building elevation 10' corridor and nonradioactive pipe chase (Fire Zones Z102 and Z128)
- August 29, 2007, Unit 2, SDGs 21, 22, and 23 areas (Fire Zones Z500-Z502 and Z506-Z508)
- August 31, 2007, Unit 2, power cable vault, electrical penetration area, electrical chase, and cable spreading room for Train A (Fire Zones Z006, Z010, Z026 and Z027)

Documents reviewed by the inspectors included:

- Applicable Fire Preplans
- CR 07-9154
- Procedure 0PGP03-ZF-0018, "Fire Protection System Operability Requirements," Revision 13

The inspectors completed six samples.

b. Findings

For more information on a licensee identified noncited violation (NCV) associated with the Unit 1 SDGs 11, 12, and 13 see Section 4OA7.

1R06 Flood Protection Measures (71111.06)

Annual External Flooding

a. Inspection Scope

The inspectors: (1) reviewed the UFSAR, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving external flooding; (2) reviewed the UFSAR and CAP to determine if the licensee identified and corrected flooding problems; (3) inspected underground bunkers/manholes to verify the adequacy of (a) sump pumps, (b) level alarm circuits, (c) cable splices subject to submergence, and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (5) walked down the below listed areas to verify the adequacy of: (a) equipment seals located below the floodline, (b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms and control circuits, and (f) temporary or removable flood barriers.

- July 26, 2007, Unit 2, diesel generator building for SDGs 21, 22, and 23

Documents reviewed by the inspectors included:

- Calculation MC05044, "Flooding Calculation for the DGB," Revision 2
- Calculation NC09710, "Facility Response Analysis for DGB Flooding and Spray Effects," Revision 2
- CRs 95-903, 07-10661, 07-10669, 07-10670

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

Biennial Heat Sink Performance

.1 Performance of Testing, Maintenance, and Inspection Activities

a. Inspection Scope

Inspection Module 71111.07, "Heat Sink Performance," requires on a biennial basis that a sample of two or three heat exchangers are to be reviewed. The inspector selected three heat exchangers that were directly connected to the safety-related service water system. The inspector reviewed the licensee's testing and/or inspection and cleaning methodology for the following heat exchangers:

- SDG jacket water heat exchangers
- SDG lube oil heat exchangers
- CCW/ECW heat exchangers

Specifically, the inspector verified proper extrapolation of test conditions to design conditions, appropriate use of test instrumentation, and appropriate accounting for instrument inaccuracies. The inspector discussed chemical controls used to avoid fouling and heat exchanger test, inspection, and cleaning results. The inspector reviewed the methods and results of heat exchanger inspection and cleaning, verified that the methods used to inspect and clean were consistent with industry standards, and ensured that the as-found results were appropriately dispositioned such that the final conditions were acceptable. Additionally, the inspector verified that the licensee appropriately trended the heat exchanger test results and inspection and cleaning results. The inspector assessed the causes of the trends and noted that the licensee took necessary actions for any step changes in these trends.

The inspector completed three inspection samples.

b. Findings

No findings of significance were identified.

.2 Verification of Conditions and Operations Consistent with Design Bases

a. Inspection Scope

For the selected heat exchangers, the inspector verified that the licensee established heat sink and heat exchanger condition and operation and test criteria that were consistent with the design assumptions. Specifically, the inspector reviewed the applicable calculations to ensure that the thermal performance test acceptance criteria for the heat exchangers were being applied consistently throughout the calculations. In addition, the inspector reviewed test data for the heat exchangers and design along with vendor-supplied information to ensure that the heat exchangers were performing within their design bases. The inspector reviewed the heat exchanger margin to verify that the capability of the heat exchangers to remove heat (BTU/hour) was greater than the heat removal rate required during design basis accident conditions.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspector verified that the licensee had entered significant heat exchanger/heat sink performance problems into the CAP. The inspector reviewed 10 CRs listed in the attachment.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

On August 21, 2007, the inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario involved prompt operator response training with minimum crew staffing. The following scenarios were evaluated: (1) steam generator narrow range level failing low, followed by a reactor coolant system (RCS) cold leg temperature failing high, and finally a main feedwater pump trip; (2) loss of Distribution Panel 1201, followed by loss of SDG lube oil pressure, and finally a loss of a reactor coolant pump where the reactor failed to trip via the manual trip lever; and (3) loss of charging flow indication, followed by loss of main feedwater level control, and finally a pressurizer pressure instrument failing high resulting in a stuck open spray valve.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the one below listed maintenance activity to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the Maintenance Rule, 10 CFR Part 50, Appendix B, and TSs.

- September 13, 2007, Units 1 and 2, essential chiller recurring issues, including maintenance rule functional failures, and repeat function failures related to failure to start/run, failure to secure, and risk ranking changing of components associated with the essential chillers requiring them to be added back into the inservice testing program

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

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

.1 Risk Assessment and Management of Risk

a. Inspection Scope

The inspectors reviewed the four below listed assessment activities to verify: (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognizes, and enters as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) that the licensee identified and corrected problems related to maintenance risk assessments.

- Week of August 6, 2007, Units 1 and 2, planned maintenance activities for the week on Unit 1 Train B, Unit 2 Train A, Unit 2 fieldbus loss resulting in a down power, and Unit 2 control room fire detection panel upgrades

- August 10, 2007, Unit 2, Emergency Response Facility Dates Acquisition and Display System (ERFDADS) inverter upgrade including temporary modifications, removal of old inverter, installation of new inverter, removal of temporary modifications, control room annunciator and indication impact, and emergency response data system impact

- Week of August 20, 2007, Units 1 and 2, planned maintenance activities for the week on Unit 1 Train D, Unit 2 Train C, Unit 1 ERFDADS inverter upgrade modifications, and Unit 2 control room fire detection panel upgrades

- September 14, Unit 1, ERFDADS inverter upgrade including temporary modifications, removal of old inverter, installation of new inverter, removal of temporary modifications, control room annunciator and indication impact, and emergency response data system impact

The inspectors completed four samples.

b. Findings

Introduction. The inspectors reviewed a self-revealing Green finding for an inadequate procedure, STI 32174927, "Conduct of Maintenance," Revision 5, for work associated with the Unit 1 ERFDADS inverter modification activities.

Description. On August 27, 2007, electrical maintenance personnel were installing a 4-inch diameter electrical conduit in the Unit 1 Train B 4160 volt switchgear room to support the ERFDADS inverter/transformer upgrade, per Design Change Package 04-9969 and Work Order (WO) 447742. The conduit was being installed in the overhead in close proximity to the voltage regulating transformer which was powering Distribution Panels (DPs) 200 and DP 300. While the electrical maintenance personnel were installing the conduit, one of the 10-foot lengths of conduit came into contact with the input breaker on the voltage regulating transformer causing it to open, de-energizing DP 200 and DP 300. The major items that DP 200 and DP 300 provided power included: (1) approximately 25 percent of the control room annunciators, (2) approximately half of the Unit 1 integrated computer system (ICS) monitors - including the rod position deviation monitor, (3) all the ICS printers in the Unit 1 control room, (4) the Unit 1 auxiliary shutdown panel ICS data, (5) all the ICS monitors in the Unit 1 technical support center, and (6) part of the Unit 1 emergency response data system.

The protective end caps on the conduit threads were being removed when this event occurred. The conduit was being supported by a step ladder on one end while the opposite end, near the breaker, was being supported by hand. All the previous pieces of conduit were prepared on the ground. Immediately following the event, the job foreman notified the control room, which had already determined the cause of the event, and a recovery plan was initiated. All loads lost were recovered in approximately 30 minutes with no additional challenges. In accordance with the conduct of maintenance procedure the crew should have discussed performing work in a safety-related area based on the following excerpts, "Include risk significant and safety-critical elements of the task . . . potential plant/system effects . . . . Take time to get acquainted with the immediate work area. This tool should be used when arriving at the physical work area and prior to interaction with risk-important systems, structures or components." Additionally, the Conduct of Maintenance procedure calls out performing prejob briefs and 360 for safety checklists. The prejob brief checklist that was performed was done per the Shaw Stone & Webster "Pre-Job Brief / Job Safety Analysis," Revision 6, and included the following point for discussion..."Proximity to energized equip." The licensee's "360 for Safety Checklist" only addresses personnel safety issues. Consequently, the guidance that was available to the crew was focused on personnel safety and did not consider working around sensitive equipment. As a result of this lack of procedural guidance for working around sensitive equipment, the crews' prejob and at the work site briefs did not recognize the potential impact of working in close proximity to sensitive equipment, transformer powering DP 200 and DP 300, with long pieces of conduit.

Analysis. The failure to adequately control the installation of conduit, due to inadequate procedural guidance resulted in the loss of approximately 25 percent of the control annunciators, was considered a performance deficiency. Traditional enforcement does not apply since there were no actual safety consequences or potential for impacting the NRC's regulatory function, and the finding was not the result of any willful violation of NRC requirements or station procedures. This finding was more than minor because it could impact the operator's ability to respond to unusual plant conditions in a timely manner due to lack of control room annunciators/indications, and the undue reliance on reports from operators in the field, and if left uncorrected, this type of control room deficiency could become a more significant safety concern.

The inspectors evaluated the significance of this finding using Inspection Manual Chapter 0609, Appendix M, "Significance Determination Process using Qualitative Criteria," and determined that the finding was of very low safety significance (Green) based on the fact that the loss of annunciators did not challenged the ability to determine emergency action levels, was of short duration, did not impact any automatic actuation systems, and the operations crew took immediate corrective and compensatory actions to restore the transformer. This observation was based on the inspectors' review of logs, the licensee's assessment review, and interviews with the operations crew. The NRC management review concurred with the determination of very low safety significance. This finding had a crosscutting aspect in the area of human performance associated with the work control component because the licensee failed to ensure that adequate guidance was available to properly evaluate specific job site conditions, and the potential for human-system interface [H.3(a)] with regard to sensitive plant equipment. This directly contributed to the event because the workers were unaware that their activities could have an impact on sensitive equipment.

<u>Enforcement</u>. No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because it occurred on non-safety related equipment. Licensee personnel entered this issue into their CAP as CR 07-12748. This issue is being treated as a finding: FIN 05000498/2007004-01, "Loss of Control Room Annunciators due to Poor Worker Material Control for ERFDADS Inverter Upgrade."

.2 <u>Emergent Work Control</u>

a. <u>Inspection Scope</u>

The inspectors: (1) verified that the licensee performed actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems and barrier integrity systems; (2) verified that emergency work-related activities such as troubleshooting, work planning/scheduling, establishing plant conditions, aligning equipment, tagging, temporary modifications, and equipment restoration did not place the plant in an unacceptable configuration; and (3) reviewed the UFSAR to determine if the licensee identified and corrected risk assessment and emergency work control problems.

- Week of July 30, 2007, Units 1 and 2, planned maintenance activities including emergent issues associated with Unit 2 essential chilled water Pump 2A breaker failure; and Unit 2 AFW Pump 24 paint chips causing unexpected governor valve linkage binding, impact distance being outside the procedural requirements, and improper latching by the trip hook and latch up lever following completion of the surveillance test

- Week of September 3, 2007, Units 1 and 2, planned maintenance activities including emergent issues associated with Unit 1 essential Chiller 12A failing to start, switchgear Channel 2 undervoltage relay failing its surveillance test, and Unit 2 pressurizer pressure control loop computer circuit repair requiring manual control of heaters and spray

Documents reviewed by the inspectors included:

- Planned Risk Profiles for Unit 1 Weeks of July 30, 2007, September 3, 2007
- Planned Risk Profiles for Unit 2 Weeks of July 30, 2007, September 3, 2007
- CRs 07-11327, 07-11533, and 07-11567
- Work Activity Risk Plan of Action 1718

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the UFSAR and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any TSs; (5) used the significance determination process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

- July 26, 2007, Units 1 and 2, water intrusion into the Units 1 and 2 diesel generator building SDG bays (CRs 95-903, 07-10661, 07-10669, and 07-10670)

- August 3, 2007, Units 1 and 2, Unit 2 essential chill water Pump 2A breaker tripping due to an overheated phase connection that was a result of a manufacturing defect to ensure torque tightness and the potential impact to other equipment with the same breaker modification already installed (CR 07-11533)

- August 8, 2007, Unit 2, AFW Pump 24 impact distance and trip hook and latch up lever engagement concerns, and governor valve linkage travel concerns due to paint chips (CRs 07-11327 and 07-11567)

- August 17, 2007, Units 1 and 2, letter from vendor on main steam isolation valves (at another facility) about wear noticed on the pilot poppet nut and stem which under shop conditions could lock up not allowing the valves to fully close; as found tested condition did not produce the lock up situation (CR 07-11727)

- October 5, 2007, Units 1 and 2, implementation of guidance from Westinghouse Technical Bulletin NSD-TB-91-02-R0 regarding anti-rotation pin failure and similar occurrence on centrifugal charging Pump 1B, and extent of condition which included the AFW pumps (CR 06-15532)

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the five below listed postmaintenance test activities of risk significant systems or components. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design-basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly realigned, and deficiencies during testing were documented. The inspectors also reviewed the UFSAR to determine if the licensee identified and corrected problems related to postmaintenance testing.

- August 3, 2007, Unit 2, AFW Pump 24 impact space adjustment due to observed unusual indications related to thermal growth of various parts and the resulting interaction on the impact distance and trip hook and latch up lever engagement

- August 3, 2007, Unit 2, essential chill water Pump 21A breaker replacement due to a shorted Phase B connection which resulted from a loose termination connection

- August 21, 2007, Unit 1, AFW Pump 14 trip arm slot lengthening on the trip and throttle valve slip link lever to alleviate concerns with the electronic trip soleniod and to allow additional margin for establishing the proper impact distance

- September 4, 2007, Unit 1, essential Chiller 12A tripping on low oil pressure after start during a chiller swap, resulting in a failed surveillance test and subsequent corrective maintenance

- September 26, 2007, Unit 1, extended range nuclear instrument NI45 low voltage power supply replacement

Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the UFSAR, procedure requirements, and TSs to ensure that the four below listed surveillance activities demonstrated that the SSC's tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated TS operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) updating of performance indicator (PI) data; (13) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria were correct; (14) reference setting data; and (15) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- July 17, 2007, Unit 2, SDG 22 performance test per Procedure 0PSP03-DG-0002, "Standby Diesel 12(22) Operability Test," Revision 31

- July 26, 2007, Unit 1, AFW Pump 14 inservice test per Procedure 0PSP03-AF-0007, "Auxiliary Feedwater Pump 14(24) Inservice Test," Revision 32

- July 30, 2007, Unit 1, containment isolation Valves 1-CC-0013, and 1-CC-MOV-0012 for CCW to residual heat removal heat exchanger per Procedure 0PSP11-CC-0007, "LLRT: M-33 CCW to RHR HX and Pump 1A/2A," Revision 8

- September 13, 2007, Unit 1, RCS leakage detection surveillance per Procedures 0PSP03-RC-0006, "Reactor Coolant Inventory," Revision 17 and 0PGP03-ZO-0046, "RCS Leakage Monitoring," Revision 4

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspector performed an inoffice review of Revision 20-5 to the South Texas Project Electric Generating Station Emergency Plan, submitted August 22, 2007. This revision changed the offsite hospital used to care for radiological injuries, changed the computer-based autodialer used to activate the emergency response organization from an onsite system to an offsite contractor, described a newly-installed meteorological instrument, updated several business names, and made minor administrative changes.

These changes were compared to their previous revisions to the criteria of NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants,” Revision 1, and to the emergency planning standards of 10 CFR 50.47(b), to determine if the revisions were adequately conducted following the requirements of 10 CFR 50.54(q). This review was not documented in a safety evaluation report and did not constitute approval of licensee changes, therefore, these revisions are subject to future inspection.

The inspector completed one sample.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

For the one below listed simulator-based training evolution contributing to drill/exercise performance, emergency response organization, and PIs, the inspectors: (1) observed the training evolution to identify any weaknesses and deficiencies in classification, notification, and protective action requirements development activities; (2) compared the identified weaknesses and deficiencies against licensee identified findings to determine whether the licensee is properly identifying failures; and (3) determined whether licensee performance is in accordance with the guidance of the NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 5 acceptance criteria.

- August 1, 2007, Unit 2, Crew E, simulator evaluation for reactor coolant leakrate that resulted in a notice of unusual event, followed by a loss of the reactor coolant barrier that resulted in an alert, followed by a high containment radiation which resulted in a site area emergency, and finally, a general emergency with protective action recommendations based on offsite dose calculations

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 PI Verification (71151)

a. Inspection Scope

Cornerstone: Mitigating Systems

The inspectors sampled licensee submittals for the one PI listed below for the period July 2006 through June 2007 for Units 1 and 2. The definitions and guidance of NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used to verify the licensee's basis for reporting each data element in order to verify the accuracy of PI data reported during the assessment period. The inspectors reviewed licensee event reports (LERs), out-of-service logs, operating logs, and the maintenance rule database as part of the assessment. Licensee PI data were also reviewed against the requirements of Procedure 0PGP05-ZN-0007, "Preparation and Submittal of NRC Performance Indicators," Revisions 3 and 4.

- safety system functional failures

The inspectors completed one sample for each unit.

Cornerstone: Barrier Integrity

The inspectors sampled licensee submittals for the two PIs listed below for the period July 2006 through June 2007 for Units 1 and 2. The definitions and guidance of NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used to verify the licensee's basis for report each data element in order to verify the accuracy of PI data reported during the assessment period. The inspectors: (1) reviewed RCS chemistry sample analyses for dose equivalent Iodine-131 and compared the results to the TS limit; (2) observed a chemistry technician obtain and analyze a RCS sample; (3) reviewed operating logs and surveillance results for measurements of RCS identified leakage; and (4) observed a surveillance test that determined RCS identified leakage. Licensee PI data were also reviewed against the requirements of Procedure 0PGP05-ZN-0007, "Preparation and Submittal of NRC Performance Indicators," Revisions 3 and 4.

- RCS specific activity
- RCS leakage

The inspectors completed two samples for each unit.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

The inspectors performed a daily screening of items entered into the licensee's CAP. This assessment was accomplished by reviewing WOs, CRs, etc... and attending corrective action review and work control meetings. The inspectors: (1) verified that equipment, human performance, and program issues were being identified by the licensee at an appropriate threshold and that the issues were entered into the CAP; (2) verified that corrective actions were commensurate with the significance of the issue; and (3) identified conditions that might warrant additional followup through other baseline inspection procedures. The inspectors used the licensee's Procedure 0PGP03-ZX-0002, "Condition Reporting Process," Revision 32, for understanding the threshold level for generating a CR.

.2 Selected Issue Followup Inspection

a. Inspection Scope

In addition to the routine review, the inspectors selected the one below listed issue for a more in-depth review. The inspectors considered the following during the review of the licensee's actions: (1) complete and accurate identification of the problem in a timely manner; (2) evaluation and disposition of operability/reportability issues; (3) consideration of extent of condition, generic implications, common cause, and previous occurrences; (4) classification and prioritization of the resolution of the problem; (5) identification of root and contributing causes of the problem; (6) identification of corrective actions; and (7) completion of corrective actions in a timely manner.

- September 7, 2007, Units 1 and 2, RCS, residual heat removal, and safety injection system leakage including leakage from the accumulators through the RCS check valve test header system into the emergency core cooling system header causing pressurization and subsequent operator workaround of having to depressurize the header to prevent lifting a relief valve

Documents reviewed by the inspectors are listed in the attachment.

b. Findings

No findings of significance were identified.

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

.1 (Closed) LERs 05000498/2007-001-00 and 05000498/2007-001-01, "Turbine-Driven AFW Pump Failed to Start During Surveillance Testing"

These LERs are associated with unresolved item (URI) 05000498/2007002-02. The inspectors reviewed LERs 05000498/2007-001-00 and 05000498/2007-001-01 to verify that the cause of the failure of the AFW pump to start was identified and that corrective actions were appropriate. See Section 4OA5 for additional information on how the event occurred, was dispositioned, and what enforcement actions were taken. These LERs are closed.

.2 Loss of Fieldbus Power Resulting in Unit 2 Downpower

a. Inspection Scope

On August 5, 2007, on Unit 2, a loss of fieldbus power from ZLC-1059 occurred, resulting in the loss of two of three heater drip pumps and two of three low pressure heater strings. This required a downpower of the unit. The unit was stabilized at approximately 45 percent RTP. The inspectors: (1) reviewed operator logs, plant computer data, and/or strip charts to evaluate operator performance in coping with this nonroutine event; (2) verified that operator actions were in accordance with the response required by plant procedures and training; and (3) verified that the licensee had identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the nonroutine evolution. The licensee documented this event in CR 07-11624. Additionally, the inspectors reviewed the root cause from a similar event that occurred in 1999, which resulted in a complicated plant transient which should have resulted in a manual scram, but was missed, documented in CR 99-17296. The inspectors did not identify any operational issues concerning this event. Troubleshooting identified a faulted power conditioner which was replaced and the unit returned to 100 percent RTP on August 6, 2007.

b. Findings

No findings of significance were identified.

4OA5 Other Activities

(Closed) URI 05000498/2007002-02, "Inadequate Procedure Leads to Inoperable Turbine-Driven AFW Pump for Longer than TSs Allowed Outage Time"

a. Inspection Scope

This URI was opened before the licensee completed the probabilistic risk assessment sensitivity analysis for manual operator action and electrical auxiliary building temperature sensitivity analysis. Additionally, as a result of the inoperability of the turbine-driven AFW pump for greater than its allowed outage time, the licensee submitted LERs 05000498/2007-001-00 and 05000498/2007-001-01, see Section 4OA3. The inspectors reviewed the LERs, corrective action documents, Unit 1 station operating logs, plant procedures, surveillance documents, and licensing memoranda. This review verified that the cause of the failure of the turbine-driven AFW pump was identified and corrective actions were appropriate. This review also verified that the licensee's probabilistic assumptions were reasonable and that model changes were appropriate in calculating the resulting core damage frequency for this event. The inspectors also reviewed the corrective action database for other past failures related to the turbine-driven AFW pump. Issues identified from this review are detailed below. This URI is closed.

b. Findings

Introduction. The inspectors reviewed a self-revealing NCV of 10 CFR Part 50, Appendix B, Criteria V, "Instructions, Procedures, and Drawings," for an inadequate surveillance test procedure for the turbine-driven AFW pump, specifically the acceptance criteria for the trip hook and the latch-up lever and the impact distance.

Description. On December 12, 2006, during the Unit 1 turbine-driven AFW Pump 14 surveillance testing, the pump failed to reach rated speed. The trip and throttle valve (MOV 0514) handswitch was taken to open in the control room to commence the surveillance test, but as the valve started to open the mechanical/electrical trip linkage on the pump tripped; thereby, disconnecting the valve from the actuator. Consequently, the valve failed to move off the closed seat. During troubleshooting activities it was identified that the impact distance between the slip link lever and the trip rod pin was below the minimum distance required, and the trip hook and latch-up lever engagement was unacceptable. Electric Power Research Institute (EPRI) guidance issued in 2002 addressed the issue of impact distance by stating that the impact distance should be 1/8 inch to 3/16 inch and that the trip hook and latch-up lever should be clean with no wear, pitting, corrosion, or other damage. Additionally, the licensee misinterpreted, and misapplied, vendor guidance on the engagement requirement between the trip hook and the latch-up lever. The licensee captured all of these concerns in CRs 06-16805 and 06-17091. The licensee implemented a design change package for both units that addresses the impact distance issues and aligns it with the EPRI guidance. Additionally, the licensee also changed the procedures to reflect EPRI guidance on the material condition, as well as the visual acceptance criteria on acceptable engagement of the trip hook and latch-up lever. Prior to this event, AFW Pump 14 was run successfully on November 16, 2006. On December 14, 2006, the licensee completed repairs/adjustments on the impact distance and successfully performed the surveillance test on AFW Pump 14. As part of the extent of condition review, the licensee verified that the Unit 2 AFW turbine-driven pump had adequate impact distance and that the trip hook and latch-up lever engagement was acceptable.

Analysis. The performance deficiency associated with this finding is the failure to identify and incorporate appropriate acceptance criteria in the maintenance and surveillance procedures which resulted in AFW Pump 14 failing to reach its rated speed due to unacceptable impact distance of the trip linkage. The inspectors determined that the issue was more than minor because it affected the mitigating systems cornerstone attributes of equipment performance and procedure quality, and it affected the cornerstone objective to ensure the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. The inspectors evaluated the violation using Inspection Manual Chapter 0609, "Significance Determination Process," Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," Phase 1 screening, and determined that it required a Phase 2 analysis because the finding represented an actual loss of safety function of a single train for greater than its TS allowed outage time. The Phase 2 analysis screened as White and the resultant Phase 3 SPAR model result was an incremental conditional core damage probability of 3E-07. The licensee's Phase 3 analysis gives recovery credit for manual operator action to locally start the turbine-driven AFW pump. Operator recovery credit is warranted because the condition that existed with the turbine-driven AFW was such that re-latching the trip hook and latch-up lever would have allowed the turbine-driven pump to be attempted to be started again. Additionally, the licensee has procedures and training in place for operators to locally start the turbine-driven pump, and the time requirement for an operator to reach the turbine-driven pump is reasonable. Consequently, the licensee's resulting incremental conditional core damage probability was 3.3E-07, or very low safety significance (Green). This issue had problem identification and resolution crosscutting aspects in that the licensee did not implement and institutionalize operating experience through changes to procedures and training programs [P.2(b)]. The licensee failed to fully evaluate specific operating experience with the turbine-driven AFW pumps to conclude that the maintenance, surveillance, and operating procedures were inadequate to ensure consistent, repeatable, and reliable measurements to critical components could be accomplished. This lack of fully implementing and institutionalizing operating experience directly contributed to the event.

Enforcement. 10 CFR Part 50, Appendix B, Criteria V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by procedures of a type appropriate to the circumstances and shall be accomplished in accordance with those procedures and shall include appropriate acceptance criteria. Contrary to this, on November 16, 2006, Procedure 0PSP03-AF-0007, "Auxiliary Feedwater Pump 14(24) Inservice Test," Revision 31, used for the TS surveillance testing of the pump was inadequate to ensure that the turbine-driven AFW pump trip and throttle valve linkage, specifically the trip hook and the latch-up lever and the impact distance, was properly reset at the end of the test. Because this procedure was inadequate, operators failed to properly reset the turbine-driven AFW Pump 14 and resulted in the pump being inoperable from November 16, 2006, until December 14, 2006, when it passed postmaintenance and surveillance testing. Since this violation is of very low safety significance (Green) and it has been entered into the licensee's CAP as CRs 06-16805 and 06-17091, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000498/2007004-02, "Inadequate Procedure Leads to Inoperable Turbine-Driven AFW Pump for Longer than TSs Allowed Outage Time."

4OA6 Management Meetings, Including Exit

Exit Meeting Summary

On August 16, 2007, the inspectors presented the heat exchanger inspection results to Mr. D. Rencurrel, Vice President Engineering, and other members of licensee management at the conclusion of the onsite inspection. The licensee stated that no proprietary information had been reviewed.

On September 24, 2007, the inspector conducted a telephonic exit meeting to present the inspection results to Mr. L. Meier, Supervisor, Emergency Preparedness, who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On October 11, 2007, the inspectors presented the inspection results of the integrated resident report inspection to Mr. E. Halpin, Site Vice President Units 1 and 2, and other members of the licensee's management staff at the conclusion of the inspection. The licensee acknowledged the findings presented. The inspectors noted that, while proprietary information was reviewed, none would be included in this report.

4OA7 Licensee-Identified Violations

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy for being dispositioned as a NCV.

- TS 6.8.1.d states, in part, that procedures shall be established, implemented, and maintained covering the fire protection program. One of the procedures that implements the fire protection program is Procedure 0PGP03-ZF-0018, “Fire Protection System Operability Requirements,” Revision 13, and requires, in part, with one or more of the required sprinkler systems inoperable . . . within 1 hour establish a continuous fire watch with backup suppression equipment. Contrary to this, on June 6, 2007, the licensee had isolated all three SDGs sprinkler systems without having stationed the required continuous fire watch within 1 hour for SDGs 11 and 12. The licensee established the required continuous fire watches within 12 hours of discovery. The licensee documented this event in CR 07-9154. The event was evaluated using the Fire Protection Significance Determination Process, Inspection Manual Chapter 0609, Appendix F, and screened out in Phase 2 as a finding of very low safety significance (Green). It screened out as very low safety significance because even though the degradation factor was high: (1) the time duration was very low, approximately 12 hours; (2) a SDG is the only item that could be impacted by a fire since, (a) only components associated with that SDG are located in the room, (b) the room is completely encompassed by a 3-hour rated fire barrier, (c) SDGs are only important with a loss of offsite power, which over a 12-hour period has a low probability, and (d) the licensee did have hourly fire watches posted for SDGs 11 and 12; (3) large early release frequency is not a concern per Inspection Manual Chapter 0609, Appendix H, because station blackout is not a contributor; and (4) SDGs are not credited for safe shutdown path. Therefore, using the actual duration factor of 12 hours (0.001), the resultant change in core damage frequency, per step 2.1, is 7.8E-7 ($0.0013*2*0.03*0.01$) which is less than 1E-6 for high degradation. The finding screens as Green.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

<u>Licensee Personnel</u>

T. Bowman, General Manager Oversight
W. Bullard, Manager, Health Physics
K. Coates, Plant General Manager
D. Cobb, STP Employee Concerns Program (EAP) Manager
R. Dunn Jr., Supervisor, Configuration Control and Analysis
R. Engen, Manager, Maintenance Engineering
T. Frawley, Manager, Plant Protection
R. Gangluff, Manager, Chemistry, Environmental and Health Physics
M. Ghrist, System Engineer
C. Grantom, Manager, PRA
S. Hafeez, Thermal-Hydraulics, NFA
E. Halpin, Site Vice President
W. Harrison, Senior Engineer, Licensing Staff
S. Head, Manager, Licensing
G. Hildebrant, Manager, Operations, Unit 2
K. House, Manager, Design Engineering
G. Janak, Manager, Operations, Unit 1
B. Jenewein, Manager Testing/Programs Engineering
R. Kersey, Design Engineering
A. McGalliard, Manager, Performance Improvement
L. Meier, Supervisor, Emergency Preparedness
J. Mertink, Manager, Operations
W. Mookhoek, Senior Engineer, Licensing
H. Murray, Manager, Maintenance
M. Murray, Manager, Systems Engineering
R. Niemann, Site ANII
G. Powell, Manager, Site Engineering
R. Ragsdale, Chemistry
M. Reddix, Manager, Security
K. Regis, ECW System Engineer
D. Rencurrel, Vice President, Engineering
K. Reynolds, Chemist
M. Ruvalcaba, Supervisor, Systems Engineering
R. Savage, Engineer Licensing Staff Specialist
W. Schulz, Design Engineering
J. Sheppard, President and CEO
D. Sicking, ECW Reliability Program Lead
K. Silverthorne, Welding Engineer
L. Spiess, NDE Level III
J. Stauber, Testing/Program
K. Taplett, Senior Engineer, Quality and Licensing

S. Thomas, Process Improvement Leadership Team
D. Towler, Manager Quality
C. Younger, Test Engineering Supervisor
D. Zink, Acting Supervisor Plant Engineering

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

05000498/2007004-01	FIN	Loss of Control Room Annunciators due to Poor Worker Material Control for ERFDADS Inverter Upgrade (Section 1R13)
05000498/2007004-02	NCV	Inadequate Procedure Leads to Inoperable Turbine-Driven AFW Pump for Longer than TSs Allowed Outage Time (Section 4OA5)

Closed

05000498/2007-001-00	LER	Turbine-Driven AFW Pump Failed to Start During Surveillance Testing (Section 4OA3)
05000498/2007-001-01	LER	Turbine-Driven AFW Pump Failed to Start During Surveillance Testing (Section 4OA3)
05000498/2007002-02	URI	Inadequate Procedure Leads to Inoperable Turbine-Driven AFW Pump for Longer than TSs Allowed Outage Time (Section 4OA5)

Discussed

None

LIST OF DOCUMENTS REVIEWED

In addition to the documents referred to in the inspection report, the following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Section 1R04: Equipment Alignment

Drawings

3V119V10002 #1, "Piping & Instrumentation Diagram - HVAC Essential Chilled Water System," Revision 13

3V119V10003 #1, "Piping & Instrumentation Diagram - HVAC Essential Chilled Water System," Revision 18

3V119V10004 #1, "Piping & Instrumentation Diagram - HVAC Essential Chilled Water System," Revision 9

5R289F05038 #2, "Piping and Instrumentation Diagram Essential Cooling Water System Train 2C," Revision 15

5R289F05039 #1, "Piping & Instrumentation Diagram Essential Cooling Water System," Revision 16

5S141F00024, "Piping & Instrumentation Diagram Auxiliary Feedwater," Revision 11

5V119V10001 #1, "Piping & Instrumentation Diagram - HVAC Essential Chilled Water System," Revision 31

Procedures

0POP02-AF-0001, "Auxiliary Feedwater," Revision 24
0POP02-CH-0005, "Essential Chiller Operation," Revision 44
0POP02-CH-0001, "Essential Chilled Water System," Revision 38
0POP02-EW-0001, "Essential Cooling Water Operations," Revision 41
0PSP03-EW-0016, "Essential Cooling Water Valve Checklist," Revision 13

Section 1R07: Heat Sink Performance

Calculations

3L02/RC9582, "CCW Water Hammer Analysis, From Penetration 1B Inlet and from RHR Heat Exchanger 1B Outlet to Penetration M-36," Revision 0

3L02/RC9582, "CCW Water Hammer From Penetration M-35 Inlet and from RHR Heat Exchanger 1B Outlet to Penetration M-36," Revision 0

MC6084, "CCW Heat Exchanger Tube Plugging," Revision 0

MC6084, "CCW Heat Exchanger Tube Plugging," Revision 1

MC6474, "Jacket Water and Lube Oil Cooler Performance," Revision 0

MC6498, “Essential Cooling Pond Thermal Performance Analysis at the South Texas Project Nuclear Power Plant,” Revision 0

CRs

03-3895	06-8963	07-7940	07-12211
06-2759	07-0845	07-8194	
06-6893	07-4999	07-9847	

Miscellaneous Documents

Quality Audit Report 06-07 System Engineers, conducted July 10 - 20, 2006

Preventive Maintenance Instructions

PM 86004486, Inspect/Clean CCW Heat Exchanger
PM 96000359, Data Collection from test of CCW/ECW heat exchanger
PM 99000480, EDG jacket water cooler
PM 99000484, EDG jacket water cooler
PM 99000489, EDG Lube oil cooler
PM 99000491, EDG Lube oil cooler

Preventive Maintenance WOs

MMD-2-99000480, WAN 249128
MMD-2-99000489, WAN 249129
MMD-2-99000491, WAN 272198
MMD-2-DG-99000480, WAN 177919
MMD-2-DG-99000486, WAN 201550
MMD-2-DG-99000489, WAN 177922
MMD-2-DG-99000491, WAN 177923
MMD-2-DG-99000493, WAN 201551
PT-1-96000359, WAN 245552
PT-1-96000359, WAN 291605
PT-2-06000252, WAN 314225

Procedures

0PCP01-ZA-0038, “Plant Chemistry Specifications,” Revision 33

0PCP01-ZQ-0004, “Cooling Water System Inspection Guidelines,” Revision 2

0PEP07-EW-001, “Performance Test of Essential Cooling Water Heat Exchangers,” Revision 6

0PGP03-ZE-0080, “Essential Cooling Water System Reliability Program,” Revision 0

0PGP04-ZA-0002, “Condition Reporting Engineering Evaluation,” Revision 6

0PMP04-ZG-0011, “Heat Exchanger Cleaning (General Guidelines and Instructions),” Revision 6

STI 32049523, Chapter 13, “Closed Cooling Water Chemistry Strategic Plan,” Revision 1

System Health Reports

Component Cooling Water, second quarter 2007
Essential Cooling Water, second quarter 2007
Standby Diesel Generators, second quarter 2007

Section 1R12: Maintenance Effectiveness

CRs

05-15959	06-4480	06-12253	07-1515
06-300	06-12021	06-16539	07-11533
06-1073	06-12037	07-9865	07-12991
06-4478	06-12043	07-980	07-13402
06-4479			

Procedures

0POP02-CH-0001, “Essential Chilled Water System,” Revision 38
0POP02-CH-0005, “Essential Chiller Operation,” Revision 44

System Health Reports

Essential Chiller (CH), third quarter 2005 through second quarter 2007

Section 1R19: Postmaintenance Testing

CRs

06-17091	07-11327	07-11567	07-12991
07-8961	07-11533	07-12422	

Procedures

0PMP04-AF-0003, “Auxiliary Feedwater Turbine Trip Throttle Valve Maintenance,” Revision 12
0PMP04-AF-0003, “Auxiliary Feedwater Turbine Trip Throttle Valve Maintenance,” Revision 14
0PMP05-PM-0001, “MCC Starter Inspection,” Revision 2
0PMP05-PM-4800, “Motor Control Center Maintenance ITE Gould,” Revision 13
0PSP03-AF-0007, “Auxiliary Feedwater Pump 14(24) Inservice Test,” Revision 32
0PSP05-NI-0045, “Extended Range Neutron Flux Channel I Calibration (N-0045),” Revision 6
VTD-T147-0008, “Terry Turbine Maintenance Guide, AFW Application,” Revision 2

Work Authorization Number

287773	319688	344047	345436
303507	335488	344075	345437
311800	340856		

Section 4OA2: Identification and Resolution of Problems

CRs

01-2187	03-14479	05-15550	07-591
01-8941	05-6574	06-1383	07-11160
01-17580	05-12658	06-15884	
02-2246	05-15548	06-16036	

Miscellaneous

RCS check valve leak test data for past 5 cycles

Procedures

0POP02-RH-0001, "Residual Heat Removal System Operation," Revision 46
0POP07-SI-0001, "RH and SI System Leakage Troubleshooting," Revision 2
0PSP03-SI-0023, "RCS Pressure Isolation Check Valve Leak Test," Revision 14

LIST OF ACRONYMS

AFW	auxiliary feedwater
ASME	American Society of Mechanical Engineers
CAP	corrective action program
CCW	component cooling water
CFR	Code of Federal Regulations
CR	condition report
DP	distribution panel
ECW	essential cooling water
EPRI	Electric Power Research Institute
ERFDADS	emergency response facility data acquisition and display system
ICS	integrated computer system
LER	Licensee Event Report
NCV	noncited violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PI	performance indicator
RCS	reactor coolant system
RTP	rated thermal power
SDG	standby diesel generator
SSC	structure, system, and component
TS	Technical Specification

UFSAR	Updated Final Safety Analysis Report
URI	unresolved item
WO	work order

Phase 3 Analysis
South Texas Turbine-Driven Auxiliary Feedwater Pump Failure

The analyst estimated the risk associated with the failure of the Unit 1 turbine-driven auxiliary feedwater pump on December 12, 2006.

<u>Assumptions</u>:

1. The analyst assumed that the turbine-driven auxiliary feedwater pump would have failed to start at any time following its last successful run on November 16, 2006, until the surveillance test failure that occurred on December 12, 2006, a period of 26 days. This conservatively assumed that the failure state of the trip throttle valve was established immediately following the November surveillance test.

2. The turbine-driven auxiliary feedwater pump could have been recovered by an operator locally resetting the trip mechanism. The SPAR-H Human Reliability Analysis Method, INL/EXT-05-00509, was used to estimate the probability that operators would fail to recover the pump within 1 hour, the most restrictive time in the SPAR model. The following assignments were made for the performance shaping factors:

Performance Shaping Factor	Diagnosis (0.01)	Action (0.001)
Available Time	Time Required (10)	Time Required (10)
Stress	High (2)	High (2)
Complexity	Nominal (1)	Nominal (1)
Experience/Training	High (0.5)	High (0.5)
Total	0.1	0.01
Overall Total HRA	0.11	

A new basic event (TDAFWP fails to start because of trip mechanism) was added to the turbine-driven auxiliary feedwater pump fail-to-start fault tree with the failure probability set at the non-recovery probability (0.11) and reset to zero for the base case.

<u>Analysis</u>:

The South Texas SPAR model, Revision 3.21, dated October 28, 2005, was used in the SAPHIRE code. A truncation of 1E-12 was used and average test and maintenance was assumed. The result was 5.679E-7/yr. For the 26-day exposure of this condition, the delta-CDF is 5.679E-7/yr. (26 days/365 days/yr) = 4.0E-8/yr. This is an internal events result only.

The dominant core damage sequence was a loss of offsite power followed by a failure of the emergency diesel generators, a failure of the turbine-driven auxiliary feedwater pump, leading to steam generator dryout, loss of heat sink, and core uncovery.

The internal events result was below the 1.0E-7 threshold for the requirement to evaluate external events or large early release.

Licensee Evaluation:

The licensee PRA analysis result for the same set of assumptions was an ICCDP of 1.87E-6. The greater than one order of magnitude difference from the NRC result was the result of a combination of several modeling differences, but was mostly attributable to initiators in the licensee PRA for loss of HVAC to vital AC switchgear rooms, which is not included in the SPAR model. These initiators accounted for nearly half of the risk attributable to the deficiency in the licensee's evaluation. Also, the risk associated with a control room fire, as well as other fire events, were accounted for in the licensee's model, but not in the SPAR analysis.

In the licensee analysis, a common cause loss of ventilation to the vital switchgear rooms accounted for greater than 50 percent of the risk of the condition. They performed a thermal analysis of the rooms to determine whether loss of cooling would result in switchgear equipment failure and a plant transient.

The revised licensee analysis provided updated quantitative core damage risk results by crediting local start of the turbine-driven auxiliary feedwater pump for more reactor trip initiators than previously credited. In addition, consideration was given to the core damage risk reduction benefit of the feedwater and condensate systems as an alternate steam generator makeup source for the loss of vital switchgear ventilation initiator. Newly-developed switchgear room heatup and steam generator dryout studies supported the time necessary for operator response to align the feedwater and condensate systems during loss of vital switchgear ventilation events. The revised ICCDP was 3.3E-7.

The NRC inspectors and senior reactor analyst reviewed the licensee's revised analysis and considered it to be adequate. Based on the results of the SPAR and licensee PRA analyses, the finding was determined to have a very low risk significance (green).