UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET SW SUITE 23T85
ATLANTA, GEORGIA 30303-8931

July 25, 2002

Tennessee Valley Authority
ATTN: Mr. J. A. Scalice
Chief Nuclear Officer and
Executive Vice President
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: SEQUOYAH NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 50-327/02-02 AND 50-328/02-02

Dear Mr. Scalice:

On June 29, 2002, the NRC completed an inspection at your Sequoyah Nuclear Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on July 3, 2002, with Mr. Dennis Koehl and other members of your staff.

The inspection 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, the inspectors identified two issues of very low safety significance (Green), that also were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as non-cited violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny any non-cited violation in the enclosed report, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Sequoyah.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document

Room 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/ (for Peter A. Taylor)

Paul E. Fredrickson, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket Nos. 50-327, 50-328
License Nos. DPR-77, DPR-79

Enclosure: NRC Inspection Report 50-327/02-02, 50-328/02-02
w/Attachment - Supplemental Information

cc w/encl: (See page 3)

cc w/encl:
Karl W. Singer
Senior Vice President
Nuclear Operations
Tennessee Valley Authority
Electronic Mail Distribution

Jack A. Bailey, Vice President
Engineering and Technical Services
Tennessee Valley Authority
Electronic Mail Distribution

Richard T. Purcell
Site Vice President
Sequoyah Nuclear Plant
Electronic Mail Distribution

General Counsel
Tennessee Valley Authority
Electronic Mail Distribution

Robert J. Adney, General Manager
Nuclear Assurance
Tennessee Valley Authority
Electronic Mail Distribution

Mark J. Burzynski, Manager
Nuclear Licensing
Tennessee Valley Authority
Electronic Mail Distribution

Pedro Salas, Manager
Licensing and Industry Affairs
Sequoyah Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

D. L. Koehl, Plant Manager
Sequoyah Nuclear Plant
Tennessee Valley Authority
Electronic Mail Distribution

Lawrence E. Nanney, Director
TN Dept. of Environment & Conservation
Division of Radiological Health
Electronic Mail Distribution

County Executive
Hamilton County Courthouse
Chattanooga, TN 37402-2801

Ann Harris
341 Swing Loop
Rockwood, TN 37854

John D. White, Jr., Director
Tennessee Emergency Management
Agency
Electronic Mail Distribution

Distribution w/encl: (See page 4)

Distribution w/encl:
R. W. Hernan, NRR
RIDSNRRDIPMLIPB
C. Evans (Part 72 Only)
PUBLIC

OFFICE	DRP/RII	DRP/RII	DRP/RII	DRP/RII	DRS/RII	DRS/RII	DRS/RII
SIGNATURE	PTaylor	RCarrion	RGibbs	RTelson	JReece	WBearden	KDavis
NAME	pt	pt (for)	pt (for)	pt (for)	jr	ml	kd
DATE	7/26/2002'	7/26/2002	7/26/2002	7/25/2002	7/25/2002	7/25/2002	7/25/2002
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICE	DRS/RII	DRS					
SIGNATURE	JWallo	JLenahan					
NAME	ab	jl					
DATE	7/25/2002	7/25/2002	7/ /2002	7/ /2002	7/ /2002	7/ /2002	7/ /2002
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO

OFFICIAL RECORD COPY DOCUMENT NAME: C:\ORPCheckout\FileNET\ML022070149.wpd

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-327, 50-328
License Nos:	DPR-77, DPR-79
Report Nos:	50-327/02-02, 50-328/02-02
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant, Units 1 & 2
Location:	Sequoyah Access Road Soddy-Daisy, TN 37379
Dates:	March 31, 2002 - June 29, 2002
Inspectors:	R. Gibbs, Senior Resident Inspector R. Telson, Resident Inspector J. Reece, Resident Inspector - Watts Bar W. Bearden, Reactor Inspector, (Section 1R08) J. Lenahan, Senior Reactor Inspector, (Section 1R08) R. Carrion, Project Engineer, (Sections 1R12, 1R19, and 1R22) K. Davis, Physical Security Inspector, (Sections 3PP1 and 3PP2) J. Wallo, Physical Security Inspector, (Sections 3PP1 and 3PP2)
Approved by:	P. Fredrickson, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000327-02-02, IR 05000328-02-02, Integrated inspection report, on 3/31 - 6/29/2002, Tennessee Valley Authority, Sequoyah Nuclear Plant, Units 1 and 2. Inservice inspection activities, permanent plant modifications.

The inspection was conducted by resident inspectors, reactor inspectors, a project engineer, and physical security inspectors. The inspection identified two Green findings, which were also non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609 "Significance Determination Process," (SDP). Findings for which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violation. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/index.htm.

A. Inspector Identified Findings

Cornerstone: Mitigating Systems

Green. The inspectors identified a non-cited violation of 10 CFR 50 Appendix B, Criterion III, Design Control, for failure to perform an adequate design modification review prior to modifying the starting air systems of the site's four emergency diesel generators (EDGs).

The failure to perform an adequate design modification review had a credible effect on safety because it contributed to the installation of modified EDG air start system pressure control valves (PCVs) that failed to perform as required. The modification simultaneously degraded all four of the site EDGs, reducing their reliability and necessitating corrective actions that reduced EDG availability. The finding was of very low safety significance because it did not result in an actual loss of safety function (Section 1R17).

TBD. The inspectors identified an unresolved item (URI) regarding the licensee's corrective actions concerning operation of rod control cluster assemblies (RCCAs) beyond their nominal design lifetime and an apparent failure of the RCCA at location L-11 to properly insert into the core during a May 31 Unit 2 automatic reactor trip.

The URI was determined to have a potential safety significance because an apparent RCCA failure to properly insert into the core and the extent of the condition for having a large number of RCCAs in both units were in operation beyond their nominal design lifetime. A final determination of safety significance is pending resolution of the URI (Section 4OA3.2).

Cornerstone: Barrier Integrity

Green. The inspectors identified a non-cited violation of 10 CFR 50 Appendix B, Criterion XVI, Corrective Action, for failure to promptly correct Unit 2 steel containment vessel degraded coatings and remove the accumulated rust. This identified failure resulted in the steel containment vessel condition not being corrected for approximately nine years (1990 - 1999).

The degraded condition and the corrective action finding, had a credible impact on safety because: (1) the extent of condition and its effects on the structural integrity of the steel containment vessel were previously unknown; (2) corrective actions had not been scheduled; and (3) the degraded condition may not have been identified because the licensee's inspection procedures excluded re-examination of the areas where the degraded coatings and rust exist. The degraded condition was of very low safety significance because insufficient corrosion of the steel containment vessel had occurred to affect containment integrity (Section 1R08.3).

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 appeared reasonable. The violations are listed in Section 4OA7.

Report Details

Summary of Plant Status: Unit 1 operated at or near 100 percent power for the entire inspection period.

Unit 2 began the inspection period at 99 percent power in coastdown for a scheduled refueling outage and on April 14 was removed from service. On May 20 the unit was returned to service and reached 100 percent power on May 23. On May 29 the unit was removed from service for main transformer repairs. On May 30 the unit was returned to service and on May 31 the unit automatically tripped due to a loss of raw cooling water to the main generator stator cooling system. The unit was restarted on June 1 and reached full power on June 2. The unit operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY
Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity And Emergency Preparedness

1R01 Adverse Weather Protection

.1 Summer Operations

a. Inspection Scope

The purpose of the inspection was to verify that preparations for hot weather conditions would limit the risk of hot weather related initiating events and adequately protect mitigating systems. The inspectors reviewed Procedure 0-PI-OPS-000-006.1, Summer Operation, and walked down the emergency diesel generator (EDG) building. The inspectors also checked the general operating condition of the raw cooling water and component cooling water systems (CCS) and reviewed fouling factor trend data for the CCS heat exchangers. The inspectors reviewed self assessment report SQN-M&M-01-003, Seasonal Summer Preparations, which evaluated the licensee's approach to hot weather preparations.

b. Findings

No findings of significance were identified.

.2 Tornado Watch

a. Inspection Scope

The inspectors observed the licensee respond to a tornado watch. The inspectors reviewed licensee Procedure AOP-N.02, Tornado Watch/Warning, for its effectiveness to limit the risk of tornado-related initiating events and to adequately protect mitigating systems from the effects of a tornado.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

Partial Equipment Walkdown

a. Inspection Scope

The inspectors conducted equipment alignment partial walkdowns to evaluate the operability of selected redundant trains or backup systems, listed below, with the other train or system inoperable or out-of-service. The walkdowns included a review of applicable operating procedures to determine correct system lineups and an inspection of critical components (e.g., power supplies and support systems) to identify any discrepancies that could affect operability of the redundant train or backup system.

- Alternate EDGs during period of surveillance when EDG 2B-B was inoperable
- Alternate EDGs during period of maintenance when EDG 1A-A was inoperable
- Safety injection (SI) pump 2B while SI pump 2A was inoperable

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted tours of areas important to reactor safety, listed below, to evaluate conditions related to (1) control of transient combustibles and ignition sources; (2) the material condition, operational status, and operational lineup of fire protection systems, equipment and features; and (3) the fire barriers used to prevent fire damage or fire propagation. The inspectors referenced SPP-10.10, Control of Transient Combustibles, and prefire plans, as appropriate. The specific documents reviewed are listed in the attachment.

- Refueling floor
- Reverse osmosis room
- Unit 2 auxiliary building 690' elevation containment access area
- Unit 1 auxiliary instrument room
- Unit 2 auxiliary instrument room
- 714' elevation general area of auxiliary building

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed test data associated with the 0B1 and 0B2 CCS heat exchangers. The purpose of the testing was to ensure that the heat exchanger performance was within acceptable limits. The inspectors reviewed completed test procedure 0-PI-SFT-070-002.0, Performance Testing of Component Cooling Heat Exchangers 0B1, 0B2, and discussed the results with engineering personnel. The inspectors also reviewed PER 02-004207-000.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities

.1 Unit 2 Steam Generator Inspection

a. Inspection Scope

The inspectors observed activities and reviewed selected inspection records for the eddy current examination (ET) of the steam generators (SGs). The records were compared to the Technical Specifications (TS), license amendments, and applicable industry established performance criteria to verify compliance. Qualification and certification records for examiners, equipment and procedures for the above eddy current examination activities were reviewed. Approximately 14 examples of bobbin and rotating coil inspection ET data were reviewed to evaluate the adequacy of completed data analysis. In addition, the inspectors reviewed the licensee's selection criteria for SG tubes to be plugged and in-situ tested during the cycle 11 refueling outage.

The inspectors also reviewed the licensee's most recent self-assessment report issued for the inservice inspection (ISI) program and, one corrective action report issued by a contractor, which was included in the licensee's corrective action program including the associated corrective action documentation. The inspectors used those procedures and documents listed in the attachment to evaluate licensee's SG ISI program and associated activities.

b. Findings

No findings of significance were identified.

.2 Inservice Inspection Activities

a. Inspection Scope

The inspectors observed in-process ISI activities and reviewed selected ISI records. The observations and records were compared to the TS and American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, 1995 Edition with

Addenda through 1996, to verify compliance. In addition, qualification and certification records for examiners and nondestructive examination (NDE) procedures (listed in the attachment) for the ISI examination activities listed below were reviewed. The inspectors also reviewed video tapes which documented the results of remote visual inspections performed on the Unit 2 reactor pressure vessel head penetrations in accordance with NRC Bulletin 2001 - 01. Portions of the following Unit 2 ISI examinations were observed and reviewed:

Visual (VT)

- Upper pressurizer supports
- SG upper support bolted connections on SG-1, SG-2, SG-3, and SG-4

Magnetic Particles (MT)

- Pressurizer support skirt weld

b. Findings

No findings of significance were identified.

.3 ASME Section XI, Subsection IWE - Containment Vessel Inspection

a. Inspection Scope

The inspectors observed in-process work activities and reviewed selected records. The observations and records were compared to TS 3.6.1.6, Containment Structural Integrity, ASME Boiler and Pressure Vessel Code, Subsection IWE of Section XI, 1992 Edition and 1992 Addenda, and 10 CFR 50.55a (Codes and Standards), to verify compliance. The inspectors examined the accessible interior surfaces of the steel containment vessel (SCV) in accumulator room 3 and the raceway area above the insulation panels, the moisture barriers in the raceway area, and the exterior surfaces of the SCV between elevations 740 and 760. The inspectors also examined the exterior SCV surfaces between elevation 679.8 and 691, including areas behind the emergency gas treatment system (EGTS) duct work at the concrete annulus floor (elevation 679.8) and SCV interface below horizontal stiffener “B” at elevation 680.8. The inspectors also reviewed records documenting visual inspections performed on the SCV in 1990 to address NRC Information Notice (IN) 89-79 and records documenting visual inspection of the SCV completed in 1999 to satisfy applicable requirements of TS 3.6.1.6 and ASME Section XI. In addition, the inspectors reviewed procedures and documents listed in the attachment to evaluate the implementation of licensee’s IWE - containment vessel inspection program.

b. Findings

A finding of very low safety significance (Green) was identified by the inspectors involving the identification and correction of degraded conditions of the Unit 2 steel containment vessel. This finding was also a non-cited violation (NCV) of 10 CFR 50 Appendix B, Criterion XVI, Corrective Action.

During examination of the exterior surfaces of the SCV, the inspectors identified areas with degraded coatings and rust on the SCV between horizontal stiffener “B” and the concrete annulus floor (in the proximity of the concrete - SCV interface) behind the EGTS duct work. Although access to the SCV was restricted by the EGTS duct work, and the ability to visually inspect the surface of the SCV was inhibited by the presence of an accumulation of debris on the annulus floor under the EGTS duct work and adjacent to the SCV, the inspectors determined that the coatings on the SCV were degraded and that rust was present on the SCV. A review of the records from previous inspections performed by the licensee in 1990 and 1999 disclosed that similar conditions had been identified by the licensee. The licensee’s 1990 inspection, which was performed in response to NRC IN 89-79, recommended the removal of the EGTS duct work and repair or replace the coatings within the next two or three outages. Some limited repairs were completed only in areas where there was no duct work. The licensee’s 1999 inspection records of the general visual inspection for the Unit 2 containment vessel integrity verification indicated that a work order would be initiated to repair the coatings. However, a review of completed procedure 2-SI-DXI-000-254.2, and the attached chronological test log, which was closed out on May 7, 1999, disclosed that a work order had not been initiated.

Procedure 2-SI-DXI-000-254.2, step 6.1, and paragraph 9.3 of Appendix A, specifies placing special emphasis during the visual examination on the SCV liner to concrete interface inside the annulus and raceway. Paragraph 11.6 of Appendix A requires evaluation of degraded coatings and the initiation of a corrective action document such as a work request or problem evaluation report (PER). However, note 3 on drawing number CISI-2000-C-08 states that the area behind EGTS duct work is inaccessible. Licensee personnel indicated that the drawing note was the basis for not inspecting the SCV behind the duct work. The inspectors determined that the SCV surfaces in this area did not meet the definition of an inaccessible area in accordance with ASME Section XI, IWE-1232, which list areas exempted from visual inspection. In fact, the importance of inspection of the interface between the SCV and the concrete is specifically addressed in IWE-1241 as an area which may require an augmented inspection. During the walkdown in the annulus, the inspectors also identified that one of the floor drains was blocked, resulting in the ponding of water on the annulus floor in an area, where the water was in contact with the SCV. A cover was also missing from another drain and debris had accumulated in the drain.

The degraded condition and the corrective action finding had a credible impact on safety because: (1) the extent of condition and its effects on the structural integrity of the steel containment vessel were previously unknown; (2) corrective actions had not been scheduled; and (3) the degraded condition may not have been identified because the licensee’s inspection procedures excluded re-examination of the areas where the degraded coatings and rust existed. The degraded condition was of very low safety significance because insufficient corrosion of the steel containment vessel had occurred to affect containment integrity.

10 CFR 50 Appendix B, Criterion XVI, Corrective Action, requires that conditions adverse to quality be promptly identified and corrected. The inspectors determined on April 23 that corrective actions for the SCV coatings and removal of rust from the SCV was neither prompt nor effective. However, because the violation was of very low safety significance

and was entered in the licensee's corrective action program, the violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy, and is identified as NCV 50-328/02-02-01, Failure to Complete Corrective Actions to Repair Deficiencies Identified During Examinations of Unit 2 Steel Containment Vessel. This deficiency is in the licensee's corrective action program as PER 02-004582-000.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed operators in the plant simulator respond to a steam generator tube rupture and a small reactor coolant system (RCS) leak with reactor coolant pump (RCP) trip. The inspectors used acceptance criteria and guidance referenced in simulator exam guide S-18 and exercise guide 273S0061 to evaluate this activity. The inspectors reviewed simulator evaluations for previously identified weaknesses and assessed the following operating crew attributes: (1) clarity and formality of communication; (2) ability to take timely action in the safe direction; (3) prioritization, interpretation, and verification of alarms; (4) correct use and implementation of procedures, including the alarm response procedures; (5) timely control board operation and manipulation, including high-risk operator actions; (6) oversight and direction provided by the shift manager, including ability to identify and implement appropriate TS actions such as reporting and emergency plan actions and notifications; and (7) the group dynamics involved in crew performance.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors sampled performance problems, listed below, from selected structures, systems, and components (SSCs). The inspectors reviewed PERs and cause determination evaluation forms (CDEF), listed in the attachment, to assess the effectiveness of the licensee's maintenance practices for these problems. The inspectors evaluated the licensee's Maintenance Rule (MR) implementation against Procedure SPP-6.6, Maintenance Rule Performance Indicator, Monitoring, Trending, and Reporting - 10 CFR 50.65 and Instruction 0-TI-SXX-000-004.0, same title as SPP-6.6. Reviews focused on: (1) MR scoping; (2) characterization of failed SSCs; (3) safety significance classifications; (4) 10 CFR 50.65 (a)(1) or (a)(2) classifications; and (5) the appropriateness of performance criteria for SSCs classified as (a)(2) or goals and corrective actions for SSCs classified as (a)(1).

- Unit 2 rod control system urgent failure
- Automatic Unit 2 reactor trip due to loss of raw cooling water
- Forced Unit 2 shutdown due to hot main transformer high voltage bushing
- Unit board 2B normal feeder breaker 1632 malfunction
- Unit 2 volume control tank outlet valve failures

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors evaluated, as appropriate for the selected work activities listed below: (1) the effectiveness of the risk assessments performed before maintenance activities were conducted; (2) the management of risk that, upon identification of an unforseen situation, necessary steps were taken to plan and control the resulting emergent work activities; and (3) that maintenance risk assessments and emergent work problems were adequately identified and resolved. The inspectors used acceptance criteria and guidance identified in Procedures SPP-7.1, Work Control Process, and Instruction 0-TI-DSM-000-007.1, Equipment to Plant Risk Matrix during these inspection activities.

- Protection set 3 rack 11 failure
- RHR pump 1B-B maintenance following RHR pump 1A-A failure to start
- RHR pump 2B main control room hand switch failure
- Centrifugal charging pump 2B-B outage after pump failure

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected functional evaluations (FEs) and PERs, and related documents listed in the attachment for issues affecting risk-significant mitigating systems to assess, as appropriate: (1) the technical adequacy of the evaluations; (2) whether continued system operability was warranted; (3) whether other existing degraded conditions were considered as compensating measures; (4) where compensatory measures were involved, whether the compensatory measures were in place, would work as intended, and were appropriately controlled; and (5) where continued operability was considered unjustified, the impact on TS limiting condition for operation (LCO) and the risk-significance in accordance with the SDP. The inspectors referenced Procedure SPP-10.6, Engineering Evaluations for Operability Determination, as needed, during the course of these inspection activities.

- Mirror insulation not installed on Unit 2 letdown isolation valves SQN-2-FCV-062-0072, -0073, and -0074 leading to increased heat load and reduced component qualified life
- RHR pump 2A-A vibration due to attached scaffolding
- Design change to Unit 2 cold leg accumulator level indication system implemented without re-scaling level transmitters
- 6.9 kV Seimens circuit breaker tripped intermittently when closure was attempted remotely and manually from various non-connected configurations

- EDG 2A-A essential raw cooling water (ERCW) piping degradation caused by flow induced cavitation

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds (OWA) - Cumulative Review

a. Inspection Scope

The inspectors reviewed all open OWAs, auxiliary unit operator round deficiencies, and selected caution orders and standing orders to evaluate the cumulative effects of OWAs on the reliability, availability, and potential for misoperation of plant systems. Specifically, the cumulative effects were evaluated for the potential to: (1) increase initiating event frequency, (2) affect multiple mitigating systems, or (3) affect the ability of operators to respond in a correct and timely manner to plant transients and accidents. The inspectors also assessed whether OWAs were being identified and entered into the corrective action program at an appropriate threshold. The specific documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed applicable sections of the FSAR, starting air system drawings, supporting analyses, TS, and related PERs to evaluate the licensee's actions regarding the substitution of EDG starting air system pressure control valves (PCVs) of a different design than originally specified. The inspectors also reviewed plant modification procedures and held discussions with engineering personnel regarding the acceptability of the PCV substitutions.

b. Findings

A finding of very low safety significance (Green) was identified by the inspectors for failure to perform an adequate design modification review prior to modifying the starting air systems of the site's four EDGs. This finding was also a NCV of 10 CFR 50 Appendix B, Criterion III, Design Control.

In 1991 the licensee completed an equivalency evaluation authorizing the substitution of EDG starting air system PCVs of a different design than those originally installed in the site's four EDGs. According to the licensee, the change was necessary because the manufacturer stopped producing the originally specified constant-bleed relieving style pilot operated regulators. Two non-constant-bleed designs (a relieving style pilot operated regulator and a non-relieving style pilot operated regulator) were determined by the licensee to be equivalent to the original and thus acceptable as substitutes. A design modification review was not performed.

According to the vendor, the constant-bleed feature minimizes secondary pressure drop when initial flow demand is placed on the regulator. The non-constant-bleed regulators lack this function. Relieving type regulators can prevent downstream pressure buildup if a PCV begins to leak-by. The non-relieving style regulators lack this function. The inspectors considered these features to be critical PCV operating characteristics.

In the equivalency evaluation, the licensee selected and compared several critical characteristics. The inspectors identified that the evaluation, however, did not address: (1) constant-bleed vs non-constant-bleed design, (2) relieving vs non-relieving design, (3) transient response characteristics, (4) ability to recover without relief actuation to anticipated large step demand decreases, and (5) necessary configuration differences between the relieving and non-relieving design, such as the requirement to install or remove relief port plugs.

Following the substitutions, malfunctions were observed in three of four EDGs, resulting in multiple uncontrolled starting air system blowdowns. The licensee declared the EDG air starting systems to be operable but degraded because it was unclear whether the EDGs, following uncontrolled blowdowns, conformed to the licensing basis which states that stored air capacity be sufficient to crank the engine five times without recharging.

The failure to perform an adequate design modification review had a credible effect on safety because it contributed to the installation of modified EDG starting air system components that failed to perform as required. The modification simultaneously degraded all of the site EDGs, reducing their reliability and necessitating corrective actions that reduced availability. The finding was of very low safety significance (Green) because it was not determined to result in the actual loss of safety function.

10 CFR 50 Appendix B, Criterion III, Design Control, requires in part that measures be established for the selection and review for suitability of application of materials, parts, and equipment essential to safety related functions of SSCs. The design control measures shall provide for verifying or checking the adequacy of design. Design changes shall be subject to design control measures commensurate with those applied to the original design. Contrary to the above, in June 1991, design control measures associated with a modification to the EDG starting air systems, failed to verify or check the adequacy of a design modification involving the selection of substitute PCVs. However, because the violation was of very low safety significance and was entered in the licensee’s corrective action program, the violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy, and is identified as NCV 50-327, 328/02-02-02, Failure to Perform an Adequate Design Modification Review Prior to Modifying EDG Starting Air Systems. This issue is in the licensee’s corrective action program as PER 02–008077-000.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed Procedure SPP-6.3, Pre/Post Maintenance Testing (PMT) which governs the licensee's PMT process, and work orders (WO) and/or test activities, as appropriate, for selected risk-significant mitigating systems to assess whether: (1) the effect of testing on the plant had been adequately addressed by control room and/or engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing basis documents; (4) test instrumentation had current calibrations, range and accuracy consistent with the application; (5) tests were performed as written with applicable prerequisites satisfied; (6) jumpers installed or leads lifted were properly controlled; (7) test equipment was removed following testing; and (8) equipment was returned to the status required to perform its safety function. The specific documents reviewed during the inspection are listed in the attachment.

- Auxiliary feedwater (AFW) level control valve 1-FCV-3-148 PMT failure
- 125 Vdc vital battery I following jumpering of cell 18
- Intermediate range nuclear instrument channel N35 adjustment
- S/G No. 3 level transmitter (2-LT-3-148) found out of tolerance and would not calibrate during TS surveillance
- Unit board 2B normal feeder breaker 1632 malfunction

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors observed numerous activities, listed below, associated with the Unit 2 cycle 11 refueling outage. The specific documents reviewed during the inspection are listed in the attachment.

Review of Outage Plan

The inspectors reviewed the Unit 2 Cycle 11 Outage Safety Plan and verified that the licensee had appropriately considered risk, industry experience and previous site specific problems. The inspectors also ensured that the licensee had considered contingencies for loss of key safety functions.

Monitoring of Shutdown Activities

The inspectors observed portions of the plant cooldown and reviewed plant procedures to verify that TS restrictions were satisfied. Procedure 0-SI-SXX-068-127.0, RCS and Pressurizer Temperature and Pressure Limits was reviewed.

Outage Configuration Management

The inspectors reviewed the daily outage report which described the defense in depth status of the unit and verified operators were aware of changing plant configurations. On numerous occasions during the outage, the inspectors verified that the licensee maintained defense in depth commensurate with the outage risk plan. The inspectors reviewed the daily outage report which described the defense in depth status of the unit and verified operators were aware of changing plant configurations.

Clearance Activities

For selected clearances, the inspectors verified that tags were properly hung and that associated equipment was appropriately configured to support the function of the clearance. Clearance 2-62-0872A-RFO was reviewed.

Reactor Coolant System Instrumentation

The inspectors verified that selected RCS pressure, level, and temperature instrumentation were installed and configured to provide accurate indication and that instrument error was considered.

Electrical Power

The inspectors verified that the status and configurations of electrical systems met TS requirements and the outage risk control plan and that switchyard activities were controlled commensurate with safety and the outage risk control plan assumptions. The inspectors reviewed procedure OPDP-2, Switchyard Access, and checked switchyard activities in progress on numerous occasions to confirm that access was properly controlled.

Decay Heat Removal (DHR) System Monitoring

The inspectors observed DHR parameters on numerous occasions to assess proper system function and that the steam generators, when relied upon, were a viable means of backup DHR.

Spent Fuel Pool Cooling System Operation

The inspectors reviewed procedure AOP-M.06, Loss of Spent Fuel Cooling to assess outage work for potential impact on the ability of the operations staff to operate the spent pool cooling system during and after core offload. The inspectors also walked down the system after core offload to confirm proper system operation.

Inventory Control

The inspectors reviewed 1-PI-OPS-068-673.D, Daily Requirements for Reduced Inventory/Midloop Operation along with flow paths, configurations, and alternative means for inventory addition for consistency with the outage risk plan. The inspectors also reviewed activities with the potential to cause loss of inventory for adequacy of controls to prevent inventory loss. In addition the inspectors performed reviews of licensee's daily outage report, toured the main control room, and discussed with operators the availability of systems needed for inventory control.

Reactivity Control

The inspectors evaluated licensee control of reactivity for compliance with TS. The inspectors also evaluated outage activities for potential to cause unexpected reactivity changes for inclusion and proper control under the outage risk plan. The inspectors evaluated a manual reactor trip initiated on May 19 during low power physics testing when a control rod system urgent failure alarm occurred and operators were unable to insert either shutdown bank "B" or control bank "D" control rods to arrest a slight positive startup rate. The event is discussed further in paragraph 4OA3.3.

Containment Closure

The inspectors reviewed control of containment penetrations for compliance with refueling operations TS to ensure that containment closure could be achieved during selected configurations. The inspectors reviewed Procedure 0-GO-15, Containment Closure Control to confirmed that personnel responsible for closing various containment penetrations were capable of being notified as required by 0-GO-15.

Reduced Inventory and Mid-Loop Conditions

The inspectors reviewed Procedures 0-GO-13, Reactor Coolant System Drain and Fill Operations, 1-PI-OPS-068-673.D, Daily Requirements for Reduced Inventory/Midloop Operation, and 0-PI-IXX-068.001.0, Daily Requirements for Reduced Inventory/Midloop and numerous activities associated with reduced inventory and mid-loop operations with emphasis on licensee's ability to monitor and control RCS water level. The inspectors also evaluated the effect of distractions on operator ability to maintain required reactor vessel level during mid-loop operations.

Refueling Activities

The inspectors reviewed fuel handling operations for conformance with TS and portions of Procedures SPP-5.8, Special Nuclear Material Control (fuel assembly transfer forms) and AOP-M.04, Refueling Malfunctions and confirmed that the locations of selected fuel assemblies were tracked during the core reload. The inspectors also observed foreign material exclusion practices in the refueling and spent fuel pool areas.

Monitoring of Heatup and Startup Activities

The inspectors reviewed on a sampling basis that TS and administrative procedure prerequisites for mode changes were met prior to changing modes or plant configurations. The inspectors also reviewed procedure 0-SI-OPS-000-187.0, Containment Inspection and walked down accessible areas in the containment building prior to plant startup to verify that debris had not been left which could affect performance of the containment sump. The containment sump was also inspected.

Identification and Resolution of Problems

The inspectors verified that the licensee had identified problems related to refueling outage activities at an appropriate threshold and had entered these problems into the corrective action program. The inspectors reviewed PERs initiated by the licensee and for selected PERs, the inspectors reviewed corrective actions plans for their appropriateness.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed surveillance tests and/or reviewed test data of selected risk-significant SSCs conducted using the surveillance instructions, listed in the attachment to this report, to assess, as appropriate, whether the SSCs met TS, the UFSAR, and licensee procedure requirements, and to determine if the testing effectively demonstrated that the SSCs were operationally ready and capable of performing their intended safety functions.

- Loss of offsite power with safety injection test - EDG 1A-A
- Functional test of cold overpressurization protection system
- Unit 2 ice condenser door pull surveillance
- Unit 2 pressurizer power operated relief valve operability test

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill, Exercise, and Actual Events

a. Inspection Scope

The inspectors observed the licensee's green team perform a quarterly emergency drill. The inspectors focused on the licensee's ability to make accurate and timely emergency action level classifications in addition to any required protective action recommendations and subsequent notifications to the state government. The inspectors reviewed the drill scenario and observed drill performance in the control room simulator and the technical support center. The inspectors also reviewed the licensee's exercise critique to determine if the licensee assessment of performance was in accordance with applicable criteria.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP1 Access Authorization (Behavior Observation Program)

a. Inspection Scope

The inspectors reviewed the licensee's behavioral observation program to evaluate the effectiveness and proper implementation of the behavioral observation portion of the personnel screening and fitness for duty (FFD) programs. Five representatives of licensee management and five representatives assigned escort duties were interviewed to determine their understanding of the behavior observation program. The inspectors evaluated the effectiveness of each individual's training, including their ability to recognize aberrant behavioral traits, indications of narcotic and alcohol use, and knowledge of work call-out reporting procedures.

The inspectors reviewed the licensee's Semi-Annual FFD report for the period July through December 2001, a sample of the licensee's Problem Evaluation Reports (PERs) and Security Event Logs for March 2001 through January 2002, to evaluate the licensee's threshold for recommending for cause testing for events related to human performance. In addition, the inspectors reviewed licensee's procedures and controls used by supervisors to determine whether employees were continuously observed in accordance with the established continual behavior observation program.

The licensee's activities were evaluated against requirements in the Sequoyah Nuclear Plant Physical Security Plan, associated plant procedures, and 10 CFR Part 26, Fitness For Duty Program. Specific licensee documents evaluated are described in the attachment.

b. Findings

No findings of significance were identified.

3PP2 Access Control

a. Inspection Scope

The inspectors reviewed licensee's access control procedures and associated equipment designed for their effectiveness to detect and prevent the introduction of contraband into the protected area (PA). The inspectors observation licensee's equipment testing procedures being performed by a licensee representative on in-use access control equipment and on in-service standby equipment at the site's Access Control Portal to evaluated their adequacy. The inspectors reviewed the equipment testing procedure to determine if testing was performance based and challenged the presently installed and configured site equipment. Through observation of licensee performance testing, the inspectors assessed the adequacy of the card readers and biometric hand readers located at the Vehicle Sally Port and the Access Control Portal to prevent unauthorized entry into the PA and to preclude multiple entries without logging out of the PA. The inspectors also observed and assessed in-processing searches of personnel, vehicles and packages at the same locations.

The inspectors reviewed licensee's Key and Lock Program and associated procedures for limiting and controlling vital area keys, including key inventories for calendar year 2001 and the first quarter of 2002. The inspectors selected random security duty rosters for the year 2001 to evaluate implementation of the PA foot patrol's accounting for the emergency operations keys used to gain access to vital equipment during an emergency. The inspectors discussed with members of the plant access authorization staff the safeguards in place to protect against unauthorized access to the site security computers from outside the PA.

The licensee's procedures and processes for granting unescorted access to vital area equipment were reviewed to determine if access was granted to only those personnel identified as having a need for such access. Specifically, the inspectors selected a sample of recently terminated employees to assess whether the individuals were denied vital equipment and PA access. Also, site access authorization personnel were interviewed to determined their knowledge associated with supervisors actions when maintaining the employee monthly protected and vital area access list. The inspectors reviewed the licensee's evaluations and corrective actions identified in the annual Nuclear Assurance Audit Report to determine if security-related observations were being appropriately dispositioned.

The above licensee's activity were evaluated against requirements contained in the Sequoyah Nuclear Plant Physical Security Plan, associated procedures, 10 CFR 73.55, Requirements for Physical Protection of Licensed Activities in Nuclear Power Reactors Against Radiological Sabotage, and 10 CFR 73.56, Personnel Access Authorization Requirements for Nuclear Power Plants. Specific licensee documents evaluated are described in the attachment.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Licensee records were reviewed to determine whether the submitted performance indicator (PI) statistics were calculated in accordance with the guidance contained in Nuclear Energy Institute 99-02, Regulatory Assessment Performance Indicator Guideline.

Cornerstone: Mitigating Systems

.1 Safety System Unavailability for Backup AC Power and AFW

a. Inspection Scope

The inspectors sampled plant records and data against the reported PI data for the period from January 1 through December 31, 2001 to determine the data's accuracy and completeness. The inspectors also discussed with cognizant engineering personnel the methods used for accumulating the PI data. In addition, the inspectors reviewed the licensee's corrective action program to determine if any problems with the collection of PI data had occurred and if resolution was satisfactory. Documents reviewed are listed in the attachment.

b. Findings

No findings of significance were identified.

Cornerstone: Physical Protection

.2 Protected Area Security Equipment Performance Index

a. Inspection Scope

The inspectors evaluated the licensee's Performance Indicator (PI) data associated with the Intrusion Detection System (IDS) and Closed Circuit Television (CCTV) to determine if the licensee provided accurate reporting for compensatory time relative to equipment degradation for the PA equipment PI. The evaluation included a sample review of tracking and trending reports, equipment maintenance logs, and security event reports for the year of 2001 and the first quarter of 2002. The inspectors also independently verified the accuracy of the calculation of licensee's PI data submitted on PA equipment for the first quarter 2001. A review of a sample list of licensee's event reports and security logs for the same period were also conducted to determine the accuracy of PI data associated with the FFD/Personnel Reliability and Personnel Screening Program.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

The inspectors conducted an in-depth review of selected issues to determine whether the licensee had taken corrective actions commensurate with the significance of the issue. Attributes reviewed included, as appropriate: (1) completeness, accuracy, and timeliness of problem identification and ease of discovery; (2) evaluation and disposition of performance issues associated with maintenance effectiveness; (3) evaluation and disposition of operability/reportability issues; (4) consideration of extent of condition, generic implications, common cause and previous occurrences; (5) classification and prioritization of the problem resolution; (6) identification of root and contributing causes of the problem; (7) identification of corrective actions which were appropriately focused to correct the problem; and (8) completion of corrective actions in a timely manner.

ERCW Piping Flow-Induced Cavitation

a. Inspection Scope

The inspectors reviewed the licensee's corrective action plan (PER 02-001183-000) for ERCW piping flow-induced cavitation issues resulting in leakage from the containment spray heat exchanger 1A discharge piping that occurred on February 2, 2002.

b. Findings

No findings of significance were identified

4OA3 Event Follow-up

.1 Unit 2 Manual Reactor Trip Due to Inability to Move Control Rods

a. Inspection Scope

On May 19, the inspectors observed portions of the licensee's recovery following an uncomplicated manual reactor trip when a control rod system urgent failure alarm occurred during low power physics testing and operators were unable to insert shutdown bank "B" or control bank "D" control rods to arrest a slight positive startup rate. The inspectors reviewed PER 02-0056000-000 and NRC event notification (EN) 38928 and discussed the event with licensee personnel.

b. Findings

No findings of significance were identified.

.2 Unit 2 Automatic Trip Due to Loss of Raw Cooling Water to Main Generator Stator Cooling System

a. Inspection Scope

On May 31, the inspectors observed portions of the licensee's recovery following an uncomplicated automatic main generator trip and subsequent reactor trip from 71 percent power. The main generator trip was caused by a loss of raw cooling water to the main generator stator cooling water system. The inspectors discussed the trip with plant management, operators and engineers, walked down control panels and the local stator cooling water skid to confirm plant conditions. The inspectors also reviewed the licensee's evaluation for plant restart and information related to the rod control cluster assembly (RCCA) at core location L-11.

b. Findings

The inspectors identified a URI regarding the licensee's corrective actions for operation of RCCAs beyond their nominal design lifetime and the apparent failure of RCCA at core location L-11 to properly insert during a May 31 automatic reactor trip.

On May 31, a Unit 2 automatic main turbine trip occurred as a result of a main generator stator cooling water failure circuit actuation. The turbine trip was followed by an automatic reactor trip from approximately 71 percent reactor power. The licensee initiated PER 02-006086-000 and NRC EN 38954 to address the trip. The PER and the NRC EN both indicated that all systems responded as designed. However, licensee-identified corrective actions completed prior to restart included testing to resolve anomalous indications associated with RCCA at core location L-11.

Testing prior to restart identified no problem with the RCCA at core location L-11 analog individual rod position indication (IRPI) system. Testing deemed necessary by the licensee to demonstrate RCCA at core location L-11 operability was also performed. RCCA at core location L-11 fully inserted within the TS required time limit during rod drop testing which was performed in Mode 3 (hot standby). An evaluation of the reactivity implication should RCCA at core location L-11 fail to fully insert within the TS drop time limit was also performed and sufficient negative reactivity existed. Corrective action items regarding RCCA at core location L-11 were closed in PER 02-006086-000 and Unit 2 was restarted on June 1.

Subsequently the inspectors reviewed a preliminary licensee assessment that the rod control system had experienced a maintenance rule functional failure (MRFF) in that RCCA at core location L-11 had apparently failed to properly insert. According to IRPI as recorded by the plant computer, RCCA at core location L-11 slowed down at an indicated 17 steps, paused at approximately 15 steps for about four minutes, then settled to an indicated minus five steps 21 minutes following the trip. The inspectors discussed with the licensee that this characterization of RCCA at core location L-11 behavior appeared contrary to NRC EN 38954 and PER 02-006086-000 in that the rod control system had apparently not performed as designed.

The inspectors reviewed PER 01-011654-000, initiated December 20, 2001, and closed May 30, 2002, addressing an industry experience associated with incomplete rod insertion in the dashpot (IRID). The PER noted that excessive drag forces present for some RCCAs due to tip swelling called into question the operability of those RCCAs. The plant at which the IRID occurred used RCCAs similar to RCCA at core location L-11. The IRID was determined to be the result of RCCA absorber tip cracking and swelling due to the extended use of the RCCAs for 18.8 effective full power years (EFPY), significantly beyond their 12 EFPY vendor design life. At the time of the apparent RCCA at core location L-11 IRID, RCCA at core location L-11 and 48 other RCCAs in Unit 2 had accumulated approximately 13.4 EFPY while 29 RCCAs in Unit 1 had approximately 13.3 EFPY according to the licensee.

At the conclusion of the inspection period, the cause of the apparent RCCA at core location L-11 IRID had not been adequately addressed in the licensee's corrective action program. The inspectors could not identify an open corrective action item requiring further evaluation or corrective action. The inspectors observed that PER 02-006086-000, the only PER to explicitly address RCCA at core location L-11 performance (1) did not list system 85 (rod control) as an affected system, (2) did not explicitly question RCCA at core location L-11 or control rod system operability, (3) did not address potential degradation of RCCA at core location L-11 or the rod control system, (4) did not address the extent of condition regarding other RCCAs operating beyond the vendor-specified nominal design lifetime in Units 1 and 2, and (5) did not require a rod control system functional evaluation. Pending receipt of requested additional information and NRC staff review, the issue is identified as URI 50-327, 328/02-02-05, Corrective Actions Related to the Apparent Failure of RCCA L-11 to Properly Insert.

The URI was determined to have potential safety significance because it raised questions regarding both an apparent RCCA failure to properly insert and the associated extent of the condition in that a large number of RCCAs in both units were in operation beyond their nominal design lifetime. A final determination of safety significance is pending resolution of the URI.

4OA5 Other

(Closed) Temporary Instruction(TI) 2515/145, Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles (NRC Bulletin 2001-01)

a. Inspection Scope

The inspectors assessed the condition of the reactor pressure vessel (RPV) closure head based on direct examination of live remote video imagery, observation of licensee inspection activities, and by sampling recorded audio-video and written inspection records. The inspectors also assessed the licensee’s ability to distinguish small boron deposits on the RPV head.

b. Findings

The inspectors determined that the licensee’s visual examination conducted during Unit 2 Cycle 11 refueling outage to address the integrity of the RPV closure head was effective. A total of 83 RPV closure head penetrations were examined. No penetrations indicated boron leakage in the area of the annulus associated with control rod drive mechanism (CRDM) nozzle weld cracking and no evidence of RPV closure head degradation was identified. Initially penetration, No. 75, could not be satisfactorily assessed for leakage due to the existence of boron residue attributed to a Conoseal leakage (a mechanical joint). The leaking Conoseal was repaired, the boron residue removed, and the area inspected.

The examination was performed by qualified and knowledgeable members of the licensee’s inspection services organization with support from an outside contractor. Any suspect areas were also reviewed by a qualified licensee metallurgical engineer. Licensee inspectors were certified for visual acuity, visual non-destructive examination (VT1), and received task-specific qualification for boric acid corrosion inspection.

According to the licensee, the visual examination was designed to incorporate the recommendations of the Electric Power Research Institute's Technical Report, Visual Examination for Leakage of PWR Reactor Head Penetrations on Top of RPV Head. The visual examination was conducted in accordance with the licensee procedures, N-VT-17, Visual Examination For Leakage of PWR Head Penetrations, and SPP-9.7, Corrosion Control Program.

The visual inspection appeared to be capable of detecting relatively small boron deposits and thus capable of identifying primary water stress corrosion cracking (PWSCC) for through-wall cracks where a pathway exists for boron to extrude from the penetration annulus. The methodology would not detect PWSCC in the absence of the characteristic “popcorn-like” appearance of extruded boron deposits or visible corrosion. Examiners relied on industry experience regarding the visual characteristics of boron deposits in determining that existing residue was not boron. None of the residue was chemically tested to confirm the absence or presence of boron.

The inspection revealed accumulated debris, insulation, dirt, and residual boron apparently from sources other than the closure head penetrations. The most notable boron residue was determined to be the result of leakage from a Conoseal mechanical connection located at penetration No. 75. The sides of some CRDM nozzles exhibited evidence of what appeared to be faint fan-blown boron streaking originating from above. The majority of penetrations had debris on the up-hill side. The amount of debris varied from light, with no significant impact on the quality of the examination, to heavy. For those penetrations where an effective examination could not be obtained in the presence of the debris, compressed air at approximately 30 psi was directed to remove the debris and the areas were reinspected. The inspectors questioned whether this practice satisfied licensee procedure N-VT-17 paragraph 5.2, which required that caution be taken not to wipe off, smear, or disturb any boron deposits that may be present on the surface of the head without first determining the source and relevance of the boron deposits. In general, the head surface was covered with a coating of dust that became heavier further up on the head.

The inspection was completed using a tracked tethered magnetic crawler outfitted with twin high resolution color cameras (one forward, one aft), LED illumination, and a low pressure air source used to blow small bits of debris from the viewing area. Access to the examination area was obtained by lifting the insulation shroud approximately five inches from the vessel head. The crawler was then navigated across the RPV closure head surface between each row of CRDM penetrations. The results of the video inspection were recorded on Digital 8 video cassettes with audio annotation and accompanied by an operator's narrative log and sketch showing the crawler's route.

There were few significant issues to impede effective examination. Boron deposits from a pre-existing Conoseal leak identified as “L-15" above CRDM No. 75 prevented an effective examination for detection of boron originating in the annulus area of this CRDM. Some penetrations had restricted viewing in the area of the annulus on the up-hill side due to insulation support rings that had separated from the insulation structure and slid down the CRDM nozzle, blocking the camera's view. Although portions of the annulus region could not be seen in these instances, no evidence of boron was noted outside of the insulation collars. Following the inspection the licensee assessed the remaining deposits and decided not to remove them. The inspectors questioned whether that decision was consistent with licensee procedure N-VT-17, paragraph 6.7, which stated that after proper documentation, it is important to remove deposits before the next examination.

The total radiation dose received by examination personnel, excluding work to raise and restore the RPV closure head insulating shroud, was 137 mrem. The inspector noted that this dose might have been further reduced by eliminating the exposure to the worker who validated the crawler's emergence from each inspected row. Fixed camera-viewable markers at the start and end of each row would have permitted the crawler's operator and subsequent video tape viewers to validate crawler location without requiring a worker to loiter in the radiation field adjacent to the RPV closure head. However, this would not have negated the occasional need for a worker at the head to guide the crawler's tether.

4OA6 Meetings, including Exit

The inspectors presented the inspection results to Mr. Dennis Koehl, Plant Manager, and other members of licensee management on July 3, 2002. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee Identified Violations

The following findings of very low significance were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as non-cited violation (NCV).

NCV Tracking Number	Requirement Licensee Failed to Meet
50-328/02-02-03	(Green) TS 6.8.1.a, Procedures and Programs, requires that written procedures be implemented covering the activities recommended in Appendix A of Regulatory Guide 1.33, Rev. 2 (Paragraph 1). Paragraph 1 requires written procedures for equipment control (e.g., locking and tagging) be implemented. Contrary to these requirements, on May 7, the licensee failed to follow Procedure SPP-10.2, Clearance Program, Rev. 3S1, Step 3.4.I.9, to ensure that the Unit 2 centrifugal charging pumps' (CCP) suction valve from the volume control tank, 2-FCV-62-132, was properly isolated for maintenance activities. This issue is in the licensee's corrective action program as PER 02-005087-000.
50-327, 328/02-02-04	(Green) 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Programs, requires, in part, that activities affecting quality shall be prescribed by documented instructions of a type appropriate to the circumstances and the activities shall be accomplished according to those instructions. Contrary to these requirements, between 1993 and 1994, the licensee failed to provide documented

guidance which defined the elements and standards of an effective cavitation program. This issue is in the licensee's corrective action program as PERs 02-001183-000 and 02-003735-000.

SUPPLEMENTAL INFORMATION
PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Bajraszewski, Licensing Engineer
G. Buchanan, Supervisor, Component Engineering
T. Carson, Maintenance Manager
H. Cothran, Steam Generator Manager
D. Clift, Acting Maintenance and Modifications Manager
E. Freeman, Operations Manager
J. Gates, Business & Work Performance Manager
J. Govlary, ISI Program Engineer
C. Kent, Radcon/Chemistry Manager
D. Koehl, Plant Manager
M. Lorek, Assistant Plant Manager
D. Lundy, Site Engineering Manager
R. Purcell, Site Vice President
R. Rogers, Design Manager
P. Salas, Licensing and Industry Affairs Manager
J. Smith, Site Licensing Supervisor
K. Stephens, Security Manager
G. Wade, ISI/NDE Supervisor
J. Whitaker, ISI Coordinator

NRC

R. Bernhard, Region II Senior Reactor Analyst

ITEMS OPENED AND CLOSED

Opened and Closed

50-328/02-02-01	NCV	Failure to Complete Corrective Actions to Repair Deficiencies Identified During Examinations of the Unit 2 Steel Containment Vessel (Section 1R08.3).
50-327, 328/02-02-02	NCV	Failure to Perform an Adequate Design Modification Review Prior to Modifying EDG Starting Air Systems (Section 1R17).
50-328/02-02-03	NCV	Failure to Ensure CCP Suction Valve from VCT was Properly Isolated During Maintenance Activities (Section 4OA7).

50-327, 328/02-02-04	NCV	Failure to Provide Guidance for an Effective Cavitation Program (Section 4OA7).

<u>Opened</u>

50-327, 328/02-02-05	URI	Corrective Actions Related to the Apparent Failure of RCCA L-11 to Properly Insert (Section 4OA3.2).

<u>Closed</u>

2515/145	TI	Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles (NRC Bulletin 2001-01).

LIST OF DOCUMENTS REVIEWED

1R05 Fire Protection

- Open Combustible Evaluation Permit ID 2002-002, Rad Con Control Point Elevation 690
- SPP-10.10, Control of Transient Combustibles, Rev. 1
- Transient Combustible Evaluation No. 2002-001, Auxiliary Bldg. Elevation 734 Room A-10
- Fire Area Documents FAA-074,-039, and-077

1R08 Inservice Inspection Procedures

- Surveillance Instruction, 0-SI-SXI-068-114.2, Steam Generator Tubing Inservice Inspection and Augmented Inspection
- Steam Generator Eddy Current Examination Guidelines
- Non-Destructive Examination (NDE) Procedure, N-VT-1, Visual Examination Procedure for ASME Section XI Preservice and Inservice
- NDE Procedure, N-MT-6, Magnetic Particle Examination for ASME and ANSI Code Components and Welds
- NDE Procedure, N-VT-15, Visual Examination of Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Plants
- Periodic Instruction, 0-PI-DXI-000-116.1, ASME Section XI IWE/IWL Containment Inservice Inspection Program, Units 1 and 2
- Surveillance Instruction, 2-SI-DXI-000-114.2, ASME Section XI ISI/NDE Program, Units 1 and 2
- Surveillance Instruction, 2-SI-DXI-000-254.2, Containment Vessel Integrity Verification, Unit 2, Rev 2
- TVA Standard, SPP-9.1, ASME Section XI

Other Documents

- Self-Assessment Report CRP-SG-01-001, Steam Generator Program
- Seqouyah Nuclear Plant Unit 2 Cycle 10 12-Month Steam Generator Inspection Report and 90-Day Report for Voltage-Based Alternate Repair Criteria, dated 1/30/2001
- Seqouyah Nuclear Plant Unit 2 Cycle 11, Steam Generator Tube Degration Assessment, dated April 2002
- Westinghouse CAPS report, 303723-001, Incorrect calibration standard serial numbers in EDDYNET summaries
- Drawing Number 48N427, Structural Steel Equipment Supports, Upper Steam Generator Support
- Drawing Number 48N428, Structural Steel Equipment Supports, Pressurizer Support
- Work Request (WR) B754748, Inspect Unit 1 Containment Vessel Steel Liner
- WR B792042, Inspect Unit 2 Containment Vessel Steel Liner, dated 3/26/90
- WR B127182, Corrosion of Liner to Concrete Interface, dated 6/17/98
- Design Change Notice (DCN) No. Q-03689, Inspection of Unit 2 Containment, dated 9/21/90

- DCN No. Q-05129, Inspection of Unit 1 Containment, dated 5/8/90
- NRC Information Notice 89-79, Degraded Coatings and Corrosion of Steel Containment Vessels, dated 12/1/89

1R12 Maintenance Rule Implementation

- PER 02-003849-000, 02-003850-000, Control and service air compressor “C” tripped on surge alarm causing control air header pressure to decrease to approximately 89 psig
- CDEF 1505, Unplanned capacity loss (UCLF) due to forced shutdown from excessive Unit 2 main transformer high side bushing temperatures caused by the installation of improperly sized o-rings.
- CDEF 1506, UCLF, UCLE, automatic reactor scram from 71 percent power due to loss of raw cooling water to main generator stator cooling system
- CDEF 1511
- CDEF 1515, 2-FCV-62-133 valve stem deflecting during travel such that stem mounted limit switch is not actuating
- WO 02-004067-000
- WO 02-004892-000

1R15 Operability Evaluations

- PER 02-003942-000 and FE, Mirror insulation not installed leading to increased heat load and reduced component qualified life
- PER 02-004810-000, FE, and reportability evaluation addressing DCN D20025A implemented during U2C10 without re-scaling the level transmitters
- PER 02-006264-000 and FE, Seimens 6.9 kV breaker installed for ERCW pump M-B intermittently tripped when given a close signal and when closed manually from the test position, simulated connect position, and when removed from the cubicle
- PER 02-004134-000 and FE, Excessive vibration in RHR pump 2A-A
- PER 02-003735 and related FE

1R16 Operator Work-Arounds - Cumulative Review

- Weekly listing of all OWAs including SQ99006WA, SQ01001, SQ01002, and SQ2001
- Caution orders related to Unit 1 excess letdown flow control and circulating water system lube water
- Standing order 02-008
- Listing of all auxiliary unit operator round deficiencies

1R17 Permanent Plant Modifications

- Nuclear Engineering Procurement Engineering Equivalency Evaluation Form, Norgen 2 Inch Pressure Regulator, Tracking No. 58-91-079, 91-0775, RIMS No. B29-910607-106
- NORGEN Specification Sheets for R18 and 11-022 pressure regulators
- PER 01-007184-000, Uncontrolled Blowdown of 1B2 EDG Engine PCVs
- TOE 01-082-7184-00, Degraded Condition of EDG Starting Air Systems, Rev. 1
- PER 01-000489-000, Plug Identified in the Relief Port of PCV for EDG Starting Air
- PER 01-007350-000, Uncontrolled Blowdown of 2A2 EDG Engine PCVs

- PER 01-008578-000, Uncontrolled Blowdown of 2B2 EDG Engine PCVs
- PER 01-010452-000, EDG 2AA failed to start from standby given a local idle start signal
- PER 02-000896-000, Inadequate EDG 2BB PCV O-ring lubrication PMT
- PER 01-011168-000, Incorrect PER classification on 2AA EDG failure to start
- PER 02-002348-000, EDG 1AA airstart test procedure problem
- PER 02-001424-000, EDG 2BB failed to start during drag test
- PER 02-003236-000, PCV equivalency evaluation relied on vendor verbal discussion
- PER 02-003722-000, EDG 2AA failed to start during testing
- PER 02-003168-000, Potential vulnerability in EDG air start system issues
- NEDP-8, Technical Evaluation for Procurement of Materials and Services
- SPP-9.3, Plant Modifications and Engineering Change Control

1R19 <u>Post-Maintenance Testing</u>

- WO 020295800, Perform single cell high level equalize charge on vital battery 1 cell 18
- 0-SI-EBT-250-100.2, 125 Vdc Vital Battery Quarterly Operability
- PER 02-002957-000, 125 Vdc vital battery I cell 18
- PER 02-004061-000 and WO 02-004060-000, Nuclear instrument intermediate range channel N35 malfunction
- 1-SI-ICC-003-148.B, Channel Calibration of Steam Generator 3 Motor Driven Auxiliary Feedwater Train B Level Loop 1-L-3-148

1R20 <u>Refueling and Outage Activities</u>

- 1-SI-ICC-003-148.B, Channel Calibration of Steam Generator 3 Motor Driven Auxiliary Feedwater Train B Level Loop 1-L-3-148
- Spent Fuel Pit System 078 Walkdown Log, System Health and Work Order Reports
- Work order 02-004060-000, Troubleshoot to determine and correct problem with N35
- PER 02-004512-000, PER 02-004061-000, N35 nuclear instrument channel indicated two decades higher than N36 during shutdown on April 15, 2002.
- Engineering Work Request (EWR) No. 02-NSS-068-0016 Rev. 0, Adjusting the Mansell Level Monitoring System for Unit 2 Refueling Outage
- EWR 02-NSS-068-0013-20, U2C11 Mansell Baseline Elevations
- EWR # 02-NSS-068-0015, Adjust Mansell level monitoring system.

1R22 <u>Surveillance Testing</u>

- 1-SI-IFT-068-456.0, Functional Test of RCS Cold Overpressurization Protection System PORV PCV-68-334 (PCV-456)
- 0-SI-MIN-061-109.0, Ice Condenser Intermediate And Lower Inlet Doors and Vent Curtains
- 0-MI-MXX-061-003.0, Ice Condenser Maintenance Inspections
- 2-SI-SXV-068-201.0, Pressurizer PORV Operability Test

4OA1 Performance Indicator Verification

AFW

- Engineering data sheets for January through December 2001
- PI data sheets for January through December 2001
- Operator logs for January (Unit 1) and April (Unit 2) 2001
- PER 01-000770-000, NRC identification of missed safety system unavailability

EDGs

- PI data sheets for January through December 2001
- Operator logs for August through December 2001, Units 1 and 2
- Engineering data sheets for August through October 2001
- CDEF 1393, DG 2A-A failed to start from a local idle start signal

4OA3 Event Follow-up

- PER 01-011654-000, Operating Experience Implementation referencing Westinghouse Letter 01TV-G-065 regarding Incomplete Rod Insertion
- PER 02-006086-000, Unit 2 Reactor Trip, Loss of Stator Cooling Water
- NRC Event Notification No. 38954, 4-Hour Notification of Automatic Reactor Trip
- PER 02-008088-000, Additional Implications Regarding Valid Incomplete Rod Insertion
- CDEF 1514, Maintenance Rule Functional Failure of Shutdown Bank A Control Rod L-11 Following Apparent Failure to Fully Insert
- Westinghouse Letter 96TV-G-0025, dated May 13, 1996, Sequoyah Unit 2 RCCA Inspection Indications on RCCAs R-154 and R-155 and Tip Cracking (PROPRIETARY)
- Westinghouse Letter NF-TV-02-3, dated January 9, 2002, RCCA Communication-Extended Use RCCAs (PROPRIETARY)
- Westinghouse Letter TVA-96-152, dated August 23, 1996, Sequoyah RCCA Inspection Report - U2C7 (PROPRIETARY)

4OA5 Other

TI 2515/145 Review

- NRC Bulletin 2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity
- Sequoyah Nuclear Plant (SQN) Units 1 and 2 - Response to NRC Bulletin 2002-01, dated April 2, 2002
- NRC Temporary Instruction 2515/145, Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles (NRC Bulletin 2001-01)
- NRC Bulletin 2001-01, Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles
- NRC Information Notice 2001-11, Recent Experience with Degradation of Reactor Pressure Vessel Head

- NRC Information Notice 2001-13, Possible Indicators of Ongoing Reactor Pressure Vessel Head Degradation
- Licensee Procedure SPP-9.7, Corrosion Control Program
- Licensee Procedure N-VT-17, Visual Examination For Leakage of PWR Reactor Head Penetrations