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

April 30, 2001

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 50-327/00-08 AND 50-328/00-08

Dear Mr. Scalice:

On March 31, 2001, the NRC completed an inspection at your Sequoyah Nuclear Plant, Units 1 and 2. The enclosed report presents the results of that inspection which were discussed on April 11, 2001, with Mr. Richard Purcell 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 one issue of very low safety significance (Green), that also was determined to involve a violation of NRC requirements. However, because of its very low safety significance and because it has been entered into your corrective action program, the NRC is treating this issue as a non-cited violation, 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/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-327, 50-328
License Nos:	DPR-77, DPR-79
Report Nos:	50-327/00-08, 50-328/00-08
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant, Units 1 and 2
Location:	Sequoyah Access Road Soddy-Daisy, TN 37379
Dates:	December 31, 2000 - March 31, 2001
Inspectors:	R. Gibbs, Senior Resident Inspector D. Starkey, Resident Inspector R. Telson, Resident Inspector E. Testa, Senior Health Physicist J. Kreh, Emergency Preparedness Inspector J. Blake, Senior Project Manager
Approved by:	P. Fredrickson, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000327-00-08, IR 05000328-00-08, on December 31, 2000 - March 31, 2001, Tennessee Valley Authority, Sequoyah Nuclear Plant, Units 1 and 2. Event follow-up.

The inspection was conducted by resident inspectors, a senior health physicist, a senior project manager and an emergency preparedness inspector. The inspection identified one Green finding, which was also a non-cited violation. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609 "Significance Determination Process," (SDP), and as discussed in the attached summary of the NRC's Reactor Oversight Process. 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/index.html.

A. Inspector Identified Findings

Cornerstone: Barrier Integrity

Green. A non-cited violation of Unit 1 License Condition 2.C.(9)(d) was identified, related to steam generator tube eddy current testing. During a Unit 1 March 2000 refueling outage, dented intersections for the steam generator tubes in the less than two volt category were not inspected in accordance with the requirements of the license condition.

This finding was of very low safety significance because only the barrier integrity cornerstone was affected and there was no impact other than slightly increasing the likelihood of a steam generator tube failure (Section 4OA5).

B. Licensee Identified Violations

Violations of very low significance which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee appear reasonable. These 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 100 percent power. On March 15, power was reduced to about 55 percent to perform scheduled maintenance on the main feedwater pumps. The unit returned to 100 percent power on March 17 and operated at or near 100 percent for the remainder of the inspection period.

1. REACTOR SAFETY

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

1R04 Equipment Alignment

.1 Partial Equipment Alignment

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, support systems) to identify any discrepancies which could affect operability of the redundant train or backup system.

- Motor driven auxiliary feedwater train 1B-B
- Auxiliary building gas treatment system train B
- Residual heat removal (RHR) train 1A-A

b. Findings

No findings of significance were identified.

.2 Complete Equipment Alignment

a. Inspection Scope

The inspectors performed a complete walkdown of accessible portions of the Unit 2 containment spray system. The inspectors verified proper equipment alignment by comparing actual equipment configuration to approved plant procedures, drawings, and the Updated Final Safety Analysis Report (UFSAR). The inspectors reviewed outstanding work requests, recently completed operability tests, related problem evaluation reports (PERs), and the system health report, which discussed open engineering issues, to determine if any conditions existed which would have prevented the system from fulfilling its intended safety function. The inspectors also performed a review of the corrective action program for substantive equipment alignment issues for all risk significant systems to ensure the licensee was identifying and correcting problems appropriately. Documents reviewed during the inspection included the following:

- Containment spray system flow diagram CCD No. 1,2-47W812-1
- Procedure 0-SO-72-1, Containment Spray Systems Valve Checklist 2-72-1.04, Rev. 5
- Procedure 0-SO-72-1, Containment Spray Systems Valve Checklist 2-72-1.05, Rev. 4
- Procedure 2-SI-SXP-072-201.B, Containment Spray Pump 2B-B Performance Test, Rev. 6

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Routine Fire Protection Walkdowns

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 Procedure SPP-10.10, Control of Transient Combustibles, Rev. 0, and pre-fire plans for the areas listed below, as appropriate.

- Control building 685' elevation (computer room)
- Control building 732' elevation (mechanical equipment room)
- Fire pump house
- Areas of emergency diesel generator (EDG) building related to 7-day fuel oil storage tank cleaning and EDG maintenance
- Control building 685' elevation (auxiliary instrument rooms)
- Control building 706' elevation (cable spreading room)

b. Findings

No findings of significance were identified.

.2 Annual Fire Drill Observation

a. Inspection Scope

On March 14, the inspectors observed a fire brigade drill in the 480-volt board room 1A located in the control building, which is a risk significant fire area. The inspectors evaluated the licensee's readiness to prevent and fight fires, including the use of fire fighting equipment, the use of pre-fire plans, the donning and use of protective clothing and self-contained breathing apparatus, and communications between the fire brigade and plant operations. In addition, the inspectors verified that the licensee's drill objectives acceptance criteria were met.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

On January 16, the inspectors observed operators in the plant simulator respond to a loss of heat sink scenario. The inspectors observed the crew's: (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 technical specifications (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 portions of selected structures, systems or components (SSCs), listed below, as a result of performance problems, to assess the effectiveness of the licensee's maintenance practices. The inspectors evaluated the licensee's Maintenance Rule (MR) implementation against Procedure SPP-6.6, Maintenance Rule Performance Indicator, Monitoring, Trending, and Reporting, Rev 5; NUMARC 93-01, Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Rev. 2; and Instruction 0-TI-SXX-000-004.0, Maintenance Rule Performance Indicator, Monitoring, Trending, and Reporting, Rev. 9. Reviews focused on: (1) MR scoping; (2) characterization of failed SSCs; (3) safety significance classifications; (4) 10CFR 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).

SSC	Related Documents
Main control room air handling unit A-A motor adjustment stud failure	Cause determination evaluation form (CDEF) 1226, PER 01-000769-000
EDG 1A-A room exhaust fan 1A failed bearing	Work order (WO) 01-00501-000; O-SO-82-1, Diesel Generator 1A-A, Rev. 15
Safety injection 1A-A pump room cooler temperature control valve failure to fully open during valve stroking	CDEF 1238; PER 01-001238-000
EDG 2A-A ground relay 64X actuation and failure	CDEF 1212; PER 00-011360-000; December 21, 2000 Unit 1 main control room narrative logs (MCRNL)
EDG 1A-A erratic operation while attempting to unload; subsequent inability to unload below 500 Kw; following second replacement of motor operated potentiometer	PER 01-000551-000; PER 01-000572-000; January 25, 2001 MCRNL; 1-SI-OPS-082-007.A, Electrical Power System Diesel Generator 1A-A, Rev. 22
Turbine driven auxiliary feedwater (TDAFW) pump 2A-S unintended steam supply transfer	CDEF 1169; PER 00-0010126-000; WO 00-009443-000

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors evaluated, as appropriate for selected work activities: (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 referenced Procedure SPP-7.1, Work Control Process, Rev. 1, and Instruction 0-TI-DSM-000-007.1, Equipment to Plant Risk Matrix, Rev. 1, during these inspection activities.

Work/Activity	Related Documents
Component cooling water system (CCS) pump 2A-A trip fuse electrical continuity failure prevented pump load shedding capability resulting in associated EDG being declared inoperable	PER 01-001450-000, MCRNL for February 25, 2001; WO 01-001451-000
EDG 2B-B six-day scheduled outage for generator work	Daily schedule safety assessment for week of February 12, 2001; MCRNL; maintenance shift supervisor's log; EDG 2B-B Mech/Elect outage plan dated February 5, 2001; EDG 2B-B Mech/Elect outage contingency plan dated February 7, 2001
Failed input to charging system flow controller 1-HIC-62-93A	PER 01-002344-000; WO 01-002345-000; Alarm Response Procedure, 1-AR-M6-C, FS-62-93A/B, Charging Line Flow Abnormal, Rev. 21; MCRNL for March 4 and 5, 2001
Metal particles observed in oil drained from EDG 1B-B governor actuator	PER 01-000606-000; January 29, 2001 MCRNL
Inability to unload EDG 1A-A below 500 Kw and subsequent frequency control challenges following replacement of motor operated potentiometer	PER 01-000551-000; PER 01-000572-000; January 25, 2001 MCRNL
Restoration of vital inverters 2-II and 2-III output frequency and synchronization under plant load	WO 00-011613-000; WO 01-000002-000

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected technical operability evaluations (TOEs) and PERs, listed below, and related documents 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; (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, Rev. 2, as needed during the course of these inspection activities.

Operability Evaluation Inspected	Related Documents Reviewed
Square-D 8501 Type X control relays	TOE 0-00-000-8744, Rev.0; PER 00-008744-000
Increasing wear metal trends in oil analysis for EDG 2B1 and 2B2 pillow block bearings	PER 01-000736-000; Predictive Monitoring Evaluation for EDG 2B-B Pillow Block Bearing Oil, Report Number 01-005, Rev.1
SI pump 2A-A failed ASME section XI test due to low minimum flow rate	TOE 2-01-063-0335, Rev. 3; caution order, 2-TO-2001-0002-00195
Vital Inverters 2-II and 2-III loss of synchronization with output frequency and voltage drifting high	2-SI-OPS-000-003.W, Weekly Shift Log, Rev. 25; SQN-DC-V-11.6, 120-V AC Vital Instrument Power System General Design Criteria, Rev. 7; PER 00-011617-000; December 22, 2000 and subsequent MCRNL
Failure of containment spray train 2B-B due to failure of 2-FCV-67-186 to stroke open during surveillance testing	2-SI-SXV-000-201.0, Full Stroking of Category “A” and “B” Valves During Operation, Rev. 5; work request (WR) C461609; CDEF 1206
TDAFW 2A-S hot packing	2-SI-SXP-003-201.5, Turbine Driven Auxiliary Feed Water Pump 2A-S Performance Test, Rev. 8; engineering assistance request (EAR) 01-COM-003-1378

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

a. Inspection Scope

The inspectors evaluated the cumulative effects of operator workarounds (OWAs) on the reliability, availability, and potential for misoperation of systems. Specifically, the cumulative effects were evaluated for the potential to: (1) increase initiating event frequency, (2) to affect multiple mitigating systems, or (3) to 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. In addition to the below-listed related documents reviewed, inspectors referenced NRC Inspection Manual Part 9900, Resolution of Degraded and Nonconforming Conditions and related licensee instructions: SPP-3.1, Corrective Action Program, Rev. 3; OPDP-1, Paragraph 3.14, Conduct of Operations - Operator Workarounds, Rev. 0; ODM-3.7, Operator Work-Around Program, Rev. 6; and ODM 3.14, Assistant Unit Operator (AUO) Rounds Deficiency Monitoring.

Operator Work-Around Inspected	Related Documents Reviewed
Cumulative Review	Licensee self-assessment, SQN-OPS-00-007 (Operator Work-Around); Control Room Deficiencies List dated March 1, 2001; Assistant Unit Operator Work Around List dated March 1, 2001; Increased Monitoring Issues dated March 1, 2001; and active caution orders

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed Procedure SPP-6.3, Pre/Post Maintenance Testing, Rev. 1, which governs the licensee's PMT process, and WOs 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.

Post Maintenance Test Inspected	Related Documents Reviewed
Cold leg nitrogen header vent flow control valve 1-FCV-63-65	1-S0-63-1, Cold Leg Injection Accumulators, Rev. 24
Hydrogen recombiners 1A-A and 1B-B	0-SI-OPS-083-151.A, Six-Month Test Requirement on Electric Hydrogen Recombiner System Train A, Rev.6; WO 01-000143-000; PER 01-001452-000; Emergency Abnormal Procedure (EA)-268-1, Placing Hydrogen Recombiners in Service, Rev. 2

EDG 1A-A following periodic 2-year planned maintenance outage	1-SI-OPS-082-007.A, Electrical Power System Diesel Generator 1A-A, Rev. 22; WO 01-000552-000; PER 01-000551-000
TDAFW 2A-S post-maintenance test	2-SI-SXP-003-201.5, Turbine Driven Auxiliary Feed Water Pump 2A-S Performance Test, Rev. 8; EAR 01-COM-003-1378; WO 99-009366-000, 2-PI-SFT-003-727.C, TDAFW Pump Full Flow Test, Rev. 5
Failure of PMT on EDG 1A-1 and 1A-2 DC lube oil pump (vibration exceeding acceptance criteria)	PER 01-000508-000; 1-PI-MDG-082-002.A, 2-Year Preventive Maintenance of Diesel Engine Set 1-A-A, Rev. 5
EDG 1A-2 lube oil motor found operating on one phase of 3-phase power due to high knife switch resistance	PER 01-000505-000; WO 00-006866-000; WR C458502; WR C434208

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 below, to assess, as appropriate, whether the SSCs met TS, the UFSAR, and licensee procedure requirements, and to verify that the testing effectively demonstrated that the SSCs were operationally ready and capable of performing their intended safety functions.

Surveillance/Equipment Test Inspected	Related Documents Reviewed
RHR pump 1A-A	1-SI-SXP-074-201.A, Residual Heat Removal Pump 1A-A Performance Test, Rev. 5
Hydrogen recombiner 1B-B	1-SI-ICC-083-001.B, Channel Calibration of Hydrogen Recombiner Train 1B-B Indicators (1-TI-83-5002 and 1-XI-83-5005-B), Rev. 3
Primary to secondary steam generator leakage	1-SI-CEM-068-137.5, Primary-To-Secondary Leakage Via Steam Generators, Rev. 15

Vital inverter voltage and frequency limits	2-SI-OPS-000-003.W, Weekly Shift Log, Rev. 25; SQN-DC-V-11.6, 120-V AC Vital Instrument Power System General Design Criteria, Rev. 7; PER 00-011617-000; December 22, 2000 and subsequent MCRNL; January 29, 2001 engineering white paper titled "Voltage and Frequency Limitations for Vital Inverters; " January 12, 2001 Operations Department Standing Order 01-001, 2-II Vital Inverter High Frequency Impact on "B" Train RVLIS
Motor driven auxiliary feed water pump 1A-A ASME section XI testing	PERs 01-000127-000 and 01-000129-000; 1-SI-SXP-003.201.A, Motor Driven Auxiliary Feedwater Pump 1A-A Performance Test, Rev.5
Functional failure of containment spray train 2B-B due to failure of 2-FCV-67-186 to stroke open during periodic surveillance testing	2-SI-SXV-000-201.0, Full Stroking of Category "A" and "B" Valves During Operation, Rev. 5; WR C461609; CDEF 1206
TDAFW pump 2A-S performance test	2-SI-SXP-003-201.5, Turbine Driven Auxiliary Feed Water Pump 2A-S Performance Test, Rev. 8; WO 99-009366-000; 2-PI-SFT-003-727.C, TDAFW Pump Full Flow Test, Rev. 5

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed temporary alteration control form (TACF) 2-01-001-001, related to the temporary repair of a valve body to bonnet leak on the Unit 2 steam generator loop 3 atmospheric relief valve (ARV). The inspectors reviewed the modification and subsequent post-maintenance test to ensure that the ARV would remain available to provide steam generator pressure control if condenser steam dump was not available and thus avoid unnecessary lifting of steam generator safety valves. The following documents were reviewed.

- TACF 2-01-001-001
- UFSAR Section 10.3.2.1
- Procedure 0-SI-SXV-001-266.0, ASME Section XI Valve Testing, Rev. 12

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspector conducted an in-office review of revisions 49, 50, 52, 54, 56, and 58, to the Radiological Emergency Plan (REP), against the requirements of 10 CFR 50.54(q) to determine that the revisions had not decreased REP effectiveness. All of the listed revisions except revision 58 contained modifications to Appendix B (site-specific for Sequoyah), including changes to the EALs. Revision 58 involved changes to only the generic portion of the REP. The inspector also determined that the EAL modifications were reviewed with, and agreed upon by, State and local officials prior to implementation, as required by Section IV.B of Appendix E to 10 CFR Part 50.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstones: Occupational Radiation Safety, Public Radiation Safety

2OS3 Radiation Monitoring Instrumentation

a. Inspection Scope

The inspectors evaluated Western Area Radiological Laboratory (WARL) portable instrument shipment receipt, storage, inventory control, return shipment, calibration procedures, self-assessment and audit reports, PERs, calibration data files, interviewed instrument technicians, the health physics supervisor, and lab manager to evaluate compliance with the Radioactive Material Control Program, UFSAR, TS, 10 CFR Part 20 requirements, Offsite Dose Calculation Manual (ODCM), and Radiological Environmental Monitoring Program (REMP). In addition, the inspectors accompanied and observed an instrumentation technician performing calibration procedures on portable radiation survey instruments and electronic dosimeters.

Procedures evaluated included the following:

- RC-06 Servicing Contaminated Portable Survey Instrumentation, dated January 16, 2001
- LSAP-0014 Training and Qualification of Instrument Technicians, Rev.9
- CC-0001 Generic Criteria for Portable Radiation Survey Instrumentation, Rev. R1
- RC-04 Procedures for Surveying WARL Facilities, Rev. 3
- LSCP-0078 Calibration Procedure for the MG DMC-90, 100, and 2000-Computer Assisted, Rev. 6

- LSCP-0117 Operating Procedure for use of Beta Sources, Rev. 5
- LSCP-0107 Operation Procedure for Neutron Sources, Rev. 3
- LSCP-0102 Operation of the Radiation Calibration Facility at the Western Area Radiological Laboratory, Rev. 5
- LSCP-0065 Calibration Procedure for the Bicron Micro-Rem, Rev. 0
- LSCP-0019 Calibration Procedure for Ludlum 12-4 with Neutron Detector, Rev. 6
- LSCP-0009 Overload Test for Survey Instrumentation, Rev. 5
- LSCP-0006 Calibration Procedure for Eberline Teletector 6112B, Rev. 5
- LSAP-0039 Program Description for Portable Survey Instrument Calibration, Rev. 0

Audit and self-assessment reports evaluated included the following:

- Audit Report No. SSA9901- Plant Support Functional Area Audit, April 15, 1999
- CRP-RP-00-003 Calibration Procedures, dated March 1, 2000 to April 1, 2000
- CRP-RP-00-001 Control of Radioactive Material, dated November 15, 1999 to December 15, 1999

PERs reviewed included the following: Corporate 00-000059-000, 00-000145-000,00-000220-000 and BFN 00-011259-000

b. Findings

No findings of significance were identified.

2PS3 Radiological Environmental Monitoring Program

a. Inspection Scope

The inspectors evaluated analytical environmental procedures, self-assessment reports, cross check comparison results, daily instrument control charts, interviewed chemists and chemistry technicians, lab supervisors, and the lab manager to evaluate compliance with the ODCM, REMP, UFSAR, TSs, and 10 CFR Part 20 requirements. In addition the inspectors accompanied and observed a chemist and several chemistry technicians performing analytical procedures including a National Institute of Standards & Technology Cross Check Sample.

Procedures evaluated included the following:

- QC-104 Sample Receiving and Log-In, Rev. 9
- SR-01 Radiochemical Determination of Strontium-89,90 in Environmental Samples, Rev. 12
- I-01 Iodine-131 Activity Determination in Environmental Samples, Rev. R7
- PPS-06 SR-89,90;NI-59,63;FE-55 and TRU(PU, NP and AM/CM Determinations, Rev. 1
- PPS-01 Preparation of 10 CFR 61 Samples, Rev. 0
- QC-26 Instrument Logbook and Control Chart Maintenance, Rev. 1
- STD-01 Standardization of Carriers, Rev. 6
- SP-01 Sample Preparation, Rev. 7

Self-assessments and cross-checks evaluated included the following:

- CRP-ERMI-01-002 Radioanalytical Analysis of 10 CFR 61 and Radiological Effluent Samples, dated January 16, 2001 to January 31, 2001
- CRP-RP-00-002 Conduct of Radiological Environmental Monitoring Program (REMP), dated June 1, 2000 to June 30, 2000
- TVA Document Summary of Cross-Checks, dated February 2001
- National Institute of Standards & Technology Cross Check Sample Nos: 1343-9,1354-4,1368-7,1280-12, 1288-19, 1311-27, 1318-4, 1334-19

b. Findings

No findings of significance were identified.

4OA1 Performance Indicator Verification

The inspectors reviewed data reported to the NRC since the last performance indicator (PI) verification inspection by comparing a sample of plant records and data, as specified below, to the reported data. NEI 99-02, Regulatory Assessment Performance Indicator Guidelines, Rev. 0 and Licensee Business Practice BP-243, Performance Indicator Information to NRC, Rev. 2, were referenced. The licensee's corrective action program records were reviewed to determine if any problems with the collection of PI data had occurred and if resolution was satisfactory. When possible, plant activities that generated the PI data input were observed.

a. Inspection Scope

PI and Time Period Verified Involved	Records Reviewed
Safety system unavailability (SSU) for auxiliary feed water (AFW) system during the period from January 1 through December 31, 2000	CDEF 1169; PER 00-0010126-000; WO 00-9443-000; Unit 2 MCRNL from October 22, 2000; UFSAR Sections 10.4.7.2, Auxiliary Feedwater System, and 15.4, Condition IV - Limiting Faults
SSU for emergency AC power during the period from January 1 through December 31, 2000	CDEF 1064, MCRNL from September through December 2000, system engineer data review inputs from April through June 2000
SSU high pressure safety injection system during the period from October through December 2000	PER 01-000770-000; MCRNL from October through December 2000; system engineer logs from October through December 2000
Reactor coolant system (RCS) leak rate during the period from October through December 2000	MCRNL from October through December 2000; system engineer's logs for RCS identified leakage from October through December 2000

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up

.1 (Closed) Licensee Event Report (LER) 50-327/2000-04: Reactor Trip on Low-Low Steam Generator Level as a Result of the Loss of a Main Feedwater Pump. On September 25, 2000, while operating at 100 percent reactor power, a Unit 1 automatic power reduction was initiated when main feedwater pump (MFP) 1A tripped following the failure of its main oil pump. A reactor trip occurred on low-low steam generator (SG) level when the remaining MFP 1B was unable to provide sufficient feedwater flow.

The licensee initiated PERs 00-008586-000 and 00-008588-000 which addressed corrective actions. This event was discussed in inspection report (IR) 50-327, 328/00-06 in which inspectors identified an unresolved item (URI) 50-327, 328/00-06-04. The URI, addressed in Section 4OA3.2 below, addresses the inspectors' follow-up activities. No new issues of significance were revealed by the LER review.

.2 (Closed) URI 50-327, 328/00-06-04: Unit 1 Reactor Trip Due to Inadequate Main Feedwater Flow. On September 25, 2000, while operating at 100 percent reactor power, a Unit 1 automatic power reduction was initiated when MFP 1A tripped following the failure of its main oil pump. A reactor trip occurred on low-low SG level when the remaining MFP 1B was unable to provide sufficient feedwater flow. The licensee identified two root causes: (a) the 1A MFP oil pump failure and (b) the incorrect procedures for adjustment of MFP turbine governors which prevented the MFP 1B from reaching maximum feedwater flow. A low-low SG water level Unit 1 reactor trip subsequently occurred. This URI was opened to evaluate the circumstances related to the failure of MFP 1B to reach rated flow, the automatic trip of MFP 1A, and operator response to the event.

The inspectors reviewed the licensee's post-trip report, corrective action documents, revised procedures, and observed the adjustment of MFP turbine governors. Other than the licensee-identified root causes, no findings of significance were identified. The inspectors evaluated the licensee-identified issues as having very low safety significance, contributing only to the increased likelihood of an uncomplicated reactor trip.

.3 (Closed) LER 50-328/2000-03: Missed SI - Failure to Perform Containment Sump Level Instrument Channel Functional Tests (CFTs) on Containment Sump Level Channels. On November 9, 2000, the licensee discovered that the four SIs for the Unit 2 containment sump level instrument CFTs had not been performed on a quarterly frequency as required by TS 4.3.2.1.1. These SIs were erroneously entered as "complete" in the SI program database on June 8, 2000 and had last been performed on June 5 and 6, 2000. Upon identification of the missed SIs, the licensee immediately performed the surveillances and each containment sump level instrument channel performed satisfactorily and was determined to be operable. These issues constitute violations of minor significance that are not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. No findings of significance were identified for the event. This event was placed in the licensee's corrective action program as PER 00-010254-000. No new issues of significance were revealed by the LER review.

.4 (Closed) Licensee Event Report (LER) 50-328/2000-04: Reactor Trip Resulting From a Fault in a Main Transformer Caused by a Failed Bushing. On November 17, 2000, Unit 2 experienced an automatic turbine and reactor trip as a result of a main bank transformer failure. This event was discussed in Inspection Report (IR) 50-327, 328/00-07. The referenced IR concluded that the event had low safety significance because the trip response was uncomplicated and sufficient mitigating systems were available during the trip recovery. No findings of significance were identified for the event. This event was placed in the licensee's corrective action program as PER 00-010691-000 and PER 00-010843-000. No new issues of significance were revealed by the LER review.

.5 (Closed) URI 50-327,328/00-06-05: RHR Operating Procedures and Emergency Core Cooling System Gas Accumulation Contribute to Loss of Reactor Coolant and ECCS Inoperability. On September 26, 2000, upon placing the Unit 1 RHR in service, a low-head ECCS relief valve lifted and failed to reseat until the RHR suction valves were closed rendering the RHR system and its associated ECCS subsystems inoperable. This URI was opened to evaluate the extent of condition of this inadvertent relief valve lift, in order to identify any potential licensee performance issues.

The licensee initiated PER 00-008645-000, which determined that the root cause of the event was the presence of non-condensable gas pockets in the RHR discharge piping that were compressed when the RHR pump was started causing a pressure pulse. The PER also listed other contributing causes which the inspectors reviewed. Based on the inspectors review of the event and through discussions with engineering personnel, the inspectors concluded that the licensee's root cause assessment was reasonable. PER 00-008645-000 also stated that the as-found condition of the relief valve did not reveal internal damage nor evidence of valve malfunction, and that the lift set point was found to be acceptable. In addition the operability evaluation related to the event, TOE 1-00-063-8645, documented that the valve condition did not result in loss of functional capability of ECCS. However, the licensee did enter the appropriate TS action statement when the RHR suction valves were manually closed in an attempt to cause the relief valve to reseat. Closing the suction valves rendered both trains of RHR inoperable until the valves were reopened six hours later at which time the LCO was exited. The licensee determined that the relief valve was open for about 11 minutes.

The licensee determined that one of the contributing causes for the event involved a missed opportunity from 1995 to improve venting practices using information contained in level B PER SQ950029PER. Specifically, the licensee determined that the root causes for the September 26, 2000 event were similar to root causes in PER SQ950029PER which addressed a 1995 RHR water hammer event. The licensee had determined, subsequent to the 1995 event, that the root cause was inadequate plant design and analysis, in that, RHR piping and installed vents were not designed to adequately maintain a full system considering the possibility of minor leakage into the RHR system from the cold leg safety injection system accumulators. Some of the corrective actions from this event included an RHR procedure revision to monitor for water hammer during the ASME Section XI testing and installation of additional vent valves for improved venting. However, there were other corrective actions identified in 1995 that were not implemented that may have prevented the 2000 event from occurring. These included the venting of the containment sump suction piping and the RHR pump minimum flow line piping. The inspectors reviewed the circumstances surrounding the 1995 event and agreed that the licensee had missed an opportunity to take corrective actions to preclude repetition of excessive gas accumulation in the RHR system. The inspectors also determined that the licensee had identified this missed opportunity in the current PER.

A Phase 3 SDP analysis was performed using the NRC's Accident Sequence Precursor Model, Rev. 3, that evaluated the risk of the RHR system relief valve lift due to gas buildup during power operation. The analysis assumed that there was no loss of the low pressure ECCS injection function while the RHR relief valve was open, due to the relief valve's relatively low flow rate. The system was shut down upon discovery of the leak to reseat the relief valve, and this would result in an additional challenge of the RHR pumps to start. The Phase 3 analysis adjusted the exposure time that the system would be susceptible to the gas buildup, based on the licensee's schedule for periodic venting of the system. After adjusting for the additional start, and for the reduced time of exposure, the results of the assessment revealed that the gas buildup and subsequent lifting of the RHR relief valve was of very low safety significance.

Because the relief valve lift was determined to be of very low safety significance, the inspectors determined that the corrective action finding was also of very low safety significance. This licensee-identified finding involved a violation of 10 CFR 50 Appendix B, Criterion XVI, Corrective Action. The enforcement aspects of this finding are discussed in Section 4OA7.

4OA5 <u>Other</u>

<u>Review of Unit 1 Steam Generator (SG) Eddy Current Examination Documentation</u>

a. <u>Inspection Scope</u>

An NRC in-office review was conducted in February 2000, of licensee steam generator tube eddy current examination information obtained during a March 2000 Unit 1 refueling outage. This review was performed because of an inconsistency between the licensees's actual implementation of the eddy current testing and the testing implementation required by Unit 1 License Condition 2.C.(9)(d) issued in 1997.

b. <u>Findings</u>

One finding of very low safety significance (Green) was identified. This finding was also identified as a non-cited violation of a Unit 1 license condition related to steam generator tube eddy current inspections conducted during a March 2000 refueling outage.

Unit 1 License Condition 2.C.(9)(d) states that:

> "By May 20, 1997, TVA shall establish a steam generator inspection program that is in accordance with the commitments listed in Enclosure 2 to the TVA

> letter to the Commission on this subject dated March 12, 1997, as modified by TVA letter dated March 17, 1997."

The details of the referenced letters in the license condition provided descriptions of the type of inspection that TVA planned to conduct on dented tubes during the March 2000 unit 1 outage**.**

An enclosure to the March 12, 1997 letter states, in part that:

> "TVA will revise Sequoyah's (SQN) steam generator inspection program (0-SI-SXI-068-114.2) prior to unit restart from the Unit 1 Cycle 8 Refueling outage. The program will be revised to: ... 3) for Unit 1, adopt the inspection plans contained in Attachment 1 of Enclosure 1 of this letter for dents less than 5 volts and greater than or equal to 5 volts."

The referenced attachment provides the Unit 1 dent sampling plan for dents less than 5 volts and states:

> "TVA will sample with rotating pancake coil (RPC) in a SG all dents less than 5 volts at all tube support plate (TSP) elevations (and lower TSPs) where, based on past inspections, degradation has occurred (defining a critical area) and perform a 20% sample of the next higher TSP elevation (a buffer zone) to bound the affected area. The buffer zone, in this application, is the next higher tube support plate elevation where no degradation has been observed. This buffer zone area is to ensure that the critical area is bounded. The degradation (circumferential ODSCC or PWSCC not detected by bobbin coil) identified from the past dented TSP inspection would determine the initial sample."

The NRC review included the summary of the May 15, 2000 public meeting between NRC and TVA, documented in correspondence dated June 21, 2000 and the referenced letters in the license conditions. As discussed above, inspections were divided into two categories: those to be conducted on dents less-than-five volts and those to be conducted on dents greater-than-or-equal-to-five volts. During discussions between TVA and NRC during the May 15, 2000 meeting, concerning the inspection of dents less-than-5 volts, and also from the TVA meeting handout, the NRC learned that the TVA inspection program had further subdivided the less-than-5 volt dent category into subcategories of less-than-two volts and greater-than-or-equal-to-two volts. The dented intersections in the equal-to-or-greater-than-two volt category were inspected as described in the license condition for less-than-five volt dents, in that systematic plus point eddy current examinations were conducted on all support plate locations up to the highest, hot-leg support plate with unacceptable indications with a 20 percent sample of the dents on the next highest support plate. The dented intersections in the less-than-two volt category were not inspected in accordance with the requirements of the license condition. Instead of using a systematic inspection, the plus point eddy current inspection process was only employed at intersections where eddy current analysts had determined that the Bobbin coil dent signal was distorted and required confirmatory inspection.

The finding that a portion of the less-than-two volt dent population was not inspected by using systematic plus point eddy current examinations, would become a more significant concern, if left uncorrected, because of an increased probability of undetected circumferential indications in steam generator tubes remaining in service. At the May 15, 2000, meeting the licensee presented their case that circumferential indications at dented tube support plate intersections are not a significant safety problem. The NRC staff did not disagree with their contention but disagreed with their inspection strategy. Since associated assumptions have no other impact than slightly increasing the likelihood of a steam generator tube failure, the finding is considered to be of very low safety significance (Green). This finding of different inspections than that stated in Unit 1 License Condition 2.C.(9)(d) was also a violation of that license condition. The violation is being treated as a non-cited violation, consistent with Section VI.A 1 of the NRC Enforcement Policy, and is identified as NCV 50-327/00-08-01: Failure to Meet License Condition for Steam Generator Tube Inspection Program. The violation is in the licensee's corrective action program as PER 01-001267-000. Subsequent to this inspection period, the licensee met with the NRC on April 11, 2001 to discuss their plans to revise the steam generator inspection plan. This meeting summary was documented in correspondence dated April 20, 2000.

4OA6 Management Meetings

The inspectors presented the inspection results to Mr. Richard Purcell, Site Vice President, and other members of licensee management at the conclusion of the inspection on April 11, 2001. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

40A7 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 Violations (NCV).

NCV Tracking Number	Requirement Licensee Failed to Meet
NCV 50-327, 328/00-08-02	10 CFR 50, Appendix B, Criterion XI, Test Control, requires that a test program shall be established to assure that all testing required to demonstrate that SSCs, will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. On October 22, 2000, following an unanticipated transfer of the steam supply to the Unit 2 turbine driven auxiliary feedwater pump, due to a clogged sensing line pulsation dampener, the licensee identified that the steam supply transfer function was not being tested as part of a test

program. The transfer of the steam supply is a safety related function and is described in design documents. This issue was placed in the licensee's corrective action program as PER 00-010126-000.

NCV 50-327, 328/00-08-03 — 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires, in part, that, in the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Corrective actions for the gas accumulation contribution to a Unit 1 1995 RHR system water hammer event, documented in PER SQ950029PER, failed to preclude repetition of RHR gas accumulation contributing to a subsequent event. On September 26, 2000, insufficient venting of non-condensable gases from the RHR system contributed to an inadvertent relief valve lift, rendering the RHR system and associated emergency core cooling system subsystems inoperable for approximately six hours. This failure to preclude repetition was placed in the licensee's corrective action program as PER 00-008645-000.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

R. Purcell, Site Vice President
T. Carson, Maintenance Manager
R. Drake, Maintenance and Modifications Manager
E. Freeman, Operations Manager
J. Gates, Site Support Manager
C. Kent, Radcon/Chemistry Manager
D. Koehl, Plant Manager
M. Lorek, Assistant Plant Manager
D. Lundy, Site Engineering Manager
P. Salas, Manager of Licensing and Industry Affairs
K. Stephens, Security Manager
J. Valente, Engineering & Support Services Manager
D. Goetchus, SG & RPV Technology Manager

NRC

R. Bernhard, Region II Senior Reactor Analyst
W. Rogers, Region II Senior Reactor Analyst

ITEMS OPENED AND CLOSED

Opened and Closed

50-327/00-08-01	NCV	Failure to Meet License Condition for Steam Generator Tube Inspection Program (Section 4OA5).
50-327, 328/00-08-02	NCV	Failure to Test the Turbine Driven Auxiliary Feedwater Pump Steam Supply Transfer Function. (Section 4OA7).
50-327, 328/00-08-03	NCV	Failure to Prevent Recurrence of Excessive Gas Accumulation in the RHR System (Section 4OA7).

Closed

50-327/2000-04	LER	Reactor Trip on Low-Low Steam Generator Level as a Result of the Loss of a Main Feedwater Pump (Section 4OA3.1).
50-327, 328/00-06-04	URI	Unit 1 Reactor Trip Due to Inadequate Main Feedwater Flow (Section 4OA3.2).
50-328/2000-03	LER	Missed SI - Failure to Perform Containment Sump Level Instrument Channel Functional Tests (CFTs) on Containment Sump Level Channels (Section 4OA3.3).
50-328/2000-04	LER	Reactor Trip Resulting From a Fault in a Main Transformer Caused by a Failed Bushing (Section 4OA3.4).
50-327, 328/00-06-05	URI	RHR Operating Procedures and ECCS Gas Accumulation Contribute to Loss of Reactor Coolant and ECCS Inoperability (Section 4OA3.5)

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety

- Initiating Events
- Mitigating Systems
- Barrier Integrity
- Emergency Preparedness

Radiation Safety

- Occupational
- Public

Safeguards

- Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.