UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

October 28, 2016

Mr. Joseph W. Shea
Vice President, Nuclear Licensing
Tennessee Valley Authority
1101 Market Street, LP 3R-C
Chattanooga, TN 37402-2801]

SUBJECT: SEQUOYAH NUCLEAR PLANT – NRC INTEGRATED INSPECTION REPORT INSPECTION REPORT 05000327/2016003 and 05000328/2016003

Dear Mr. Shea:

On September 30, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Sequoyah Nuclear Plant Units 1 and 2. On October 21, the NRC inspectors discussed the results of this inspection with Mr. Pratt and other members of your staff. The results of this inspection are documented in the enclosed report.

NRC inspectors documented two findings of very low safety significance (Green) in this report. All of these findings involved violations of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2.a. of the Enforcement Policy.

Inspection Report 05000327; 328/2016002, documented an Apparent Violation (AV) 2016002-01, Isolation of Fire Suppression System to a Significant Portion of the Plant Site, for which the NRC had not yet reached a preliminary significance determination (i.e., TBD). Section 4OA5 of this report discusses the final significance determination of very low safety significance (Green). AV 2016002-01 is now closed.

If you contest the violations or significance of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement; and the NRC resident inspector at the Sequoyah Nuclear Plant.

If you disagree with a cross-cutting aspect assignment in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region II; and the NRC resident inspector at the Sequoyah Nuclear Plant.

In accordance with Title 10 of the *Code of Federal Regulations* 2.390, "Public Inspections, Exemptions, Requests for Withholding," of the NRC's "Agency Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's Agencywide Document Access and Management 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/

Alan Blamey, Branch Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket Nos.: 05000327, 05000328
License Nos.: DPR-77, DPR-79

Enclosure:
Inspection Report 05000327/2016003
and 05000328/2016003
w/Attachment: Supplemental Information

cc w/encl. Distribution via Listserv

In accordance with Title 10 of the *Code of Federal Regulations* 2.390, “Public Inspections, Exemptions, Requests for Withholding,” of the NRC’s “Agency Rules of Practice,” a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC’s Agencywide Document Access and Management 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/

Alan Blamey, Branch Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket Nos.: 05000327, 05000328
License Nos.: DPR-77, DPR-79

Enclosure:
Inspection Report 05000327/2016003
and 05000328/2016003
w/Attachment: Supplemental Information

cc Distribution via Listserv

DOCUMENT NAME: G:\DRPII\SEQUOYAH\REPORTS\2016\003\2016.003
ADAMS ACCESSION NUMBER: ML16302A383

■ SUNSI Review Complete By: A. Blamey		ADAMS ■ Yes ☐ No	■ Publicly Available ☐ Non-Publicly Available		■ Non-Sensitive ☐ Sensitive	Keyword:	
OFFICE	RII:DRP	RII:DRP	RII:DRP	RII:DRP	/RII:DRP		
NAME	G Smith	W Deschaine	J. Dodson	A Blamey	N Staples		
SIGNATURE	/RA via Email/	/RA vial Email/	/RA/	/RA/	/RA/		
DATE	10/28/2016	10/28/2016	10/28/2016	10/28/2016	10/28/2016		

OFFICIAL RECORD COPY

Letter to Joseph W. Shea from Alan Blamey dated October 28, 2016

SUBJECT: SEQUOYAH NUCLEAR PLANT – NRC INTEGRATED INSPECTION REPORT INSPECTION REPORT 05000327/2016003 and 05000328/2016003

DISTRIBUTION:
M. Kowal, RII
S. Price, RII
S. Maxey, RII
OE Mail
RIDSNRRDIRS
PUBLIC
RidsNrrPMSequoyah Resource

U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-327, 50-328
License Nos.:	DPR-77, DPR-79
Report Nos.:	05000327/2016003, 05000328/2016003
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant, Units 1 and 2
Location:	Sequoyah Access Road Soddy-Daisy, TN 37379
Dates:	July 1 – September 30, 2016
Inspectors:	G. Smith, Senior Resident Inspector W. Deschaine, Resident Inspector N. Staples, Senior Reactor Inspector
Approved by:	Alan Blamey, Chief Reactor Projects Branch 6 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000327/2016003, 05000328/2016003; 7/1-9/30/2016; Sequoyah Nuclear Plant, Units 1 and 2; (Event Follow-up and Other Areas.)

The report covered a three-month period of inspection by resident inspectors and announced inspections by region-based inspectors. There were two self-revealing violations documented in this report. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP) dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, “Components within the Cross Cutting Areas” dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC’s Enforcement Policy dated August 1, 2016. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 6.

Cornerstone: Initiating Events

- Green. A self-revealing non-cited violation (NCV) of the facility operating licenses DPR-77 and DPR-79 conditions 2.C.(16) and 2.C.(13), respectively, was identified for the licensee’s failure to properly implement the clearance process such that the fire suppression system was rendered non-functional for approximately 41 hours. The licensee inappropriately expanded an existing clearance on March 29, 2016 in order to attempt to reduce boundary valve leakage affecting existing maintenance on the fire suppression system within a valve pit. Subsequently on March 30, 2016 during fire system testing, technicians noted a lack of system pressure and it was ultimately concluded the clearance expansion had inadvertently isolated fire suppression water to a significant portion of the site. Upon discovery of the clearance error, the system was restored to a functional status. The licensee entered the issue into their corrective action program (CAP) as CR 1155763.

  The licensee’s failure to properly assess the system impact of a clearance revision for the High Pressure Fire Protection (HPFP) suppression header and enter the required FPR Operating Requirement (FOR) Action was a performance deficiency. The performance deficiency was more than minor because it was associated with the protection against external events (fire) attribute of the mitigating systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inability to pressurize the HPFP system from either the electric or diesel-driven fire pumps rendered the fire suppression system inoperable. Based on the complexities of this particular event, the inspectors concluded that Appendix M, “Significance Determination Process Using Qualitative Criteria,” of IMC 0609 should be performed in lieu of a Phase 3 analysis. Under appendix M, the Senior Reactor Analyst (SRA) performed an initial bounding evaluation using qualitative methods. The licensee submitted a detailed analysis that estimated an upper bound for the risk of the finding which was less than 1E-6. The SRA performed a review of this screening analysis as part of this SDP evaluation. In addition to the SRA review, the resident inspectors performed an independent review of the licensee’s estimation of the success of actions used to recover the isolated fire header. To the extent reviewed, the methodology and results were determined to be acceptable for use in this SDP review of this Performance Deficiency. The SRA concurred with the submitted results of the licensee’s screening analysis, and has determined the finding to be GREEN.

The inspectors determined that the finding had a cross cutting aspect of "Procedural Adherence" within the Human Performance area, because the licensee failed to consider the affect that changing a clearance order could have on the operability of the fire suppression system. (H.8). (4OA5)

Cornerstone: Barrier Integrity

- Green. A self-revealing NCV of Technical Specification 3.6.8, "Hydrogen Mitigation System (HMS)," was identified for the licensee's failure to restore an inoperable train of HMS within the 7 day completion time or place the unit in Mode 3 within the action time of 6 hours. Each train of HMS has 34 hydrogen igniters and SR 3.6.8.1 defines an operable train as one that has at least 33 igniters operable. A review of the operating history revealed the 'A' train HMS had only 31 operable igniters for a period of 91 days due to a mispositioned circuit breaker. Upon discovery of the unexpected condition, the circuit breaker was closed to restore operability to the HMS train. The licensee entered the issue into their CAP as CR 1179126.

  The licensee's failure to preclude an inoperable HMS train for more than 7 days without a subsequent plant shutdown was a performance deficiency. The performance deficiency was more than minor because it was associated with the Configuration Control attribute of Barrier Integrity cornerstone and adversely affected the cornerstone's objective to ensure the structural integrity of the containment boundary. Specifically, the finding challenged containment integrity as hydrogen igniters have a high risk significance in ice condenser style containments. The finding was screened to Green based on the fact that the loss of igniters did not affect multiple igniters in adjacent compartments. The inspectors determined that the finding had a cross cutting aspect of "Avoid Complacency" within the Human Performance area because the licensee failed to implement appropriate error reduction tools while working near the HMS circuit breakers (H.12). (4OA3)

REPORT DETAILS

Summary of Plant Status:

Unit 1 operated at or near 100 percent rated thermal power (RTP) for the entire inspection period.

Unit 2 operated at or near 100 percent RTP for the entire inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors reviewed the licensee's preparations to protect risk-significant systems from high winds. The inspectors reviewed licensee Procedure AOP-N.02, Tornado Watch/Warning, Revision 35, to assess its effectiveness in limiting the risk of tornado-related initiating events and adequately protecting mitigating systems from the effects of a tornado. The inspectors reviewed the licensee's plans to address the ramifications of potentially lasting effects that may result from high winds. The inspectors verified that operator actions specified in the licensee's adverse weather procedure maintain readiness of essential systems. The inspectors verified that required surveillances were current, or were scheduled and completed, if practical, before the onset of anticipated adverse weather conditions. The inspectors also verified that the licensee implemented periodic equipment walkdowns or other measures to ensure that the condition of plant equipment met operability requirements. This activity constituted one inspection sample, as defined in Inspection Procedure (IP) 71111.01.

b. Findings

No findings were identified.

.2 Summer Readiness of Offsite and Alternate AC Power Systems:

a. Inspection Scope

The inspectors performed the annual review of the licensee's readiness of offsite and alternate AC power systems prior to the onset of the high grid loading season. The inspectors reviewed procedures affecting these areas and the communications protocols between the transmission system operator and the licensee to verify that appropriate information is exchanged when issues arise that could impact the offsite power system. The inspectors walked down offsite power supply systems in the switchyard and the emergency diesel generators (EDGs), reviewed corrective action program documents, and interviewed appropriate plant personnel to assess deficiencies and plant readiness for summer high grid loading. Documents reviewed are listed in the Attachment. The inspectors completed one sample, as defined in IP 71111.01

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdown

a. Inspection Scope

The inspectors performed partial walkdowns of the following four systems to verify the operability of redundant or diverse trains and components when safety equipment was inoperable. The inspectors focused on identification of discrepancies that could impact the function of the system and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, walked down control system components, and determined whether selected breakers, valves, and support equipment were in the correct position to support system operation. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP. Documents reviewed are listed in the Attachment. The inspectors completed four samples, as defined in IP 71111.04.

- Unit 1 B-train Centrifugal Charging Pump (CCP) while the ‘A’ CCP was out-of-service (OOS) for planned maintenance
- ‘B’ Auxiliary Building Gas Treatment System (ABGTS) while the ‘A’ train ABGTS was OOS for planned maintenance
- Unit 2 ‘A’ EDG while the ‘B’ EDG was OOS for planned maintenance
- Unit 2 ‘A’ Residual Heat Removal (RHR)l train while the ‘B’ train RHR train was OOS for planned maintenance

.2 Complete System Walkdown

a. Inspection Scope

The inspectors performed a complete system walkdown of the radiation monitoring and support systems to verify proper equipment alignment, to identify any discrepancies that could impact the function of the system and increase risk, and to verify that the licensee properly identified and resolved equipment alignment problems that could cause events or impact the functional capability of the system.

The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), system procedures, system drawings, and system design documents to determine the correct lineup and then examined system components and their configuration to identify any discrepancies between the existing system equipment lineup and the correct lineup. During the walkdown, the inspectors reviewed the following:

Mechanical systems:

- Valves were correctly positioned and did not exhibit leakage that would impact the functions of any given valve.
- Electrical power was available as required.
- Major system components were correctly labeled, lubricated, cooled, ventilated, etc.
- Hangers and supports were correctly installed and functional.
- Essential support systems were operational.
- Ancillary equipment or debris did not interfere with system performance.
- Tagging clearances were appropriate.
- Valves were locked as required by the locked valve program.

Electrical systems:

- Breakers were correctly positioned.
- Electrical power was available as required.
- Major system components were correctly labeled.
- Cabinets, cable trays, and conduits were correctly installed and functional.
- Visible cabling appeared to be in good material condition.
- Essential support systems were operational.
- Ancillary equipment or debris did not interfere with system performance.
- Tagging clearances were appropriate.

In addition, the inspectors reviewed outstanding maintenance work requests and design issues on the system to determine whether any condition described in those work requests could adversely impact current system operability. Documents reviewed are listed in the Attachment to this report. The inspectors completed one sample, as defined in IP 71111.04.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

Fire Protection Tours

a. Inspection Scope

The inspectors conducted a tour of the six areas important to safety listed below to assess the material condition and operational status of fire protection features. The inspectors evaluated whether: combustibles and ignition sources were controlled in accordance with the licensee's administrative procedures; fire detection and suppression equipment was available for use; passive fire barriers were maintained in good material condition; and compensatory measures for out-of-service, degraded, or inoperable fire protection equipment were implemented in accordance with the licensee's fire plan. Documents reviewed are listed in the Attachment. The inspectors completed six samples, as defined in IP 71111.05.

- Emergency Raw Cooling Water Building

- U1 Additional Equipment Building
- U2 Additional Equipment Building
- CDWE Building
- Aux Building 653 Elevation
- Aux Building 669 Elevation

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Quarterly Review

a. Inspection Scope

The inspectors performed one licensed operator requalification program review. The inspectors observed a simulator session on August 22, 2016. The training scenario involved a Loop 2 RTD failing, then the PT-3-1, 1A, 1B Feedwater Header Pressure transmitters failed low, followed by the Bus duct cooling having a failure, then the operators experienced a loss of the 120V AC vital instrument power board 1-I and an Anticipated Transient without Scram, finally the scenario concluded with a Small Break Loss of Coolant Accident. The inspectors observed crew performance in terms of: communications; ability to take timely and proper actions; prioritizing, interpreting and verifying alarms; correct use and implementation of procedures, including the alarm response procedures; timely control board operation and manipulation, including high risk operator actions; oversight and direction provided by shift manager, including the ability to identify and implement appropriate Technical Specification (TS) action; and, group dynamics involved in crew performance. The inspectors also observed the evaluators' critique and reviewed simulator fidelity to verify that it matched actual plant response. Documents reviewed are listed in the Attachment. This activity constituted one inspection sample, as defined in IP 71111.11.

b. Findings

No findings were identified

.2 Quarterly Review of Licensed Operator Performance

a. Inspection Scope

The inspectors observed and assessed licensed operator performance in the main control room during periods of heightened activity or risk. The inspectors reviewed various licensee policies and procedures such as OPDP-1, Conduct of Operations, NPG-SPP-10.0, Plant Operations, and 0-GO-5, Normal Power Operation. The inspectors utilized activities such as post-maintenance testing, surveillance testing, unplanned transients, infrequent plant evolutions, plant startups and shutdowns, reactor power and turbine load changes, and refueling and other outage activities to focus on the following conduct of operations as appropriate:

- operator compliance and use of procedures
- control board manipulations
- communication between crew members
- use and interpretation of plant instruments, indications and alarms
- use of human error prevention techniques
- documentation of activities, including initials and sign-offs in procedures
- supervision of activities, including risk and reactivity management
- pre-job briefs

Documents reviewed are listed in the Attachment. This activity constituted one inspection sample, as defined in IP 71111.11.

b. Findings

No findings were identified

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the maintenance activities, cause determination evaluations (CDE), issues, and/or systems listed below to verify the effectiveness of the licensee's activities in terms of: appropriate work practices; identifying and addressing common cause failures; scoping in accordance with 10 CFR 50.65(b); characterizing reliability issues for performance; trending key parameters for condition monitoring; charging unavailability for performance; classification in accordance with 10 CFR 50.65(a)(1) or (a)(2); appropriateness of performance criteria for structure, system, or components (SSCs) and functions classified as (a)(2); and appropriateness of goals and corrective actions for SSCs and functions classified as (a)(1). Documents reviewed are listed in the Attachment. The inspectors completed two samples, as defined in IP 71111.12.

- Concurrent loss of all four 480 shutdown board room chillers on June 12, 2016
- CDE 2905 - 2A EDG Exceeded MR Unavailability Goal

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors reviewed the following five activities to determine whether appropriate risk assessments were performed prior to removing equipment from service for maintenance. The inspectors evaluated whether risk assessments were performed as required by 10 CFR 50.65 (a) (4), and were accurate and complete. When emergent work was performed, the inspectors reviewed whether plant risk was promptly reassessed and managed. The inspectors also assessed whether the licensee's risk assessment tool use and risk categories were in accordance with Standard Programs and Processes Procedure NPG-SPP-07.1, "On-Line Work Management," Revision 16 and Instruction 0-TI-DSM-000-007.1, “Risk Assessment Guidelines,” Revision 9. Documents reviewed are listed in the Attachment. The inspectors completed five samples, as defined in IP 71111.13.

- Planned ‘A’ ABGTS outage for fire suppression repairs
- Planned 1A Safety Injection pump outage
- Planned ‘C’ Service air compressor outage
- Emergent failure and loss of the Yard Area Common Board
- Unit 1 Yellow risk due to vital battery charger 1 and 1-S OOS due to unplanned failure of 1S charger

b. Findings

No findings were identified.

1R15 Operability Evaluations

a. Inspection Scope

For the four operability evaluations described in the condition reports (CRs) listed below, the inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available, such that no unrecognized increase in risk occurred. The inspectors compared the operability evaluations to UFSAR descriptions to determine if the system or component’s intended function(s) were adversely impacted. In addition, the inspectors reviewed compensatory measures implemented to determine whether the compensatory measures worked as stated and the measures were adequately controlled. The inspectors also reviewed a sampling of CRs to assess whether the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment. The inspectors completed four samples, as defined in IP 71111.15.

- CR 1169888, Test header Alignment to ECCS Header potentially causes both trains to be rendered inoperable (POE)
- CR 1197233, Emergency diesel generator 1B-B cooling water level low
- CR 1198440 and 1200028, EGTS Operability Determination
- CR 1179126, H2 Igniter breaker found open

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

Temporary Modifications

a. Inspection Scope

The inspectors reviewed the temporary modification listed below and the associated 10 CFR 50.59 screening, and compared it against the UFSAR and TS to verify whether the modification affected operability or availability of the affected system.

- Temporary modification SQN-0-2016-065-001 - Disabling the EGTS Annulus differential pressure automatic swap over circuits for Unit 1 and Unit 2

Following installation and testing, the inspectors observed indications affected by the modification, discussed them with operators, and verified that the modification was installed properly and its operation did not adversely affect safety system functions. Documents reviewed are listed in the Attachment. The inspectors completed one sample, as defined in IP 71111.18.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests associated with the five work orders (WOs) listed below to assess whether procedures and test activities ensured system operability and functional capability. The inspectors reviewed the licensee's test procedure to evaluate whether: the procedure adequately tested the safety function(s) that may have been affected by the maintenance activity; the acceptance criteria in the procedure were consistent with information in the applicable licensing basis and/or design basis documents; and the procedure had been properly reviewed and approved. The inspectors also witnessed the test or reviewed the test data to determine whether test results adequately demonstrated restoration of the affected safety function(s). Documents reviewed are listed in the Attachment. The inspectors completed five samples, as defined in IP 71111.19.

- 117862482, Replacement of pressure relief valve (2-VLV-067-1521) for the auxiliary control air compressor B
- 116690150, 2A Pressurizer Heater relay replacement
- 118035577, ISI Accumulator Tank 1 level drifting high
- 118005098, Diesel Generator starting air compressor relief lifting
- 118121022, Replacement of shutoff valve (SQN-0-VLV-082-0548-1B2) on the 1B2 EDG

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

For the three surveillance tests identified below, the inspectors assessed whether the SSCs involved in these tests satisfied the requirements described in the TS surveillance requirements, the UFSAR, applicable licensee procedures, and whether the tests demonstrated that the SSCs were capable of performing their intended safety functions. This was accomplished by witnessing testing and/or reviewing the test data. Documents reviewed are listed in the Attachment. The inspectors completed three samples, as defined in IP 71111.22.

In-Service Tests:

- 1-SI-SXP-074-201.A. Residual Heat Removal Pump 1A-A Performance Test, Revision 18
- 2-SI-SXP-074-201.B, Residual Heat Removal Pump 2B-B Performance Test, Revision 17

Routine Surveillance Tests:

- 0-SI-OPS-085-011.0, Reactivity Control Systems Moveable Control Assemblies, Revision 37

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

Resident inspectors evaluated the conduct of routine licensee emergency drill on July 26, 2016, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation (PAR) development activities. The inspectors observed emergency response operations in the simulated control room to verify that event classification and notifications were done in accordance with EPIP-1, Emergency Plan Classification Matrix, Revision 52. The inspectors also attended the licensee critique of the drill to compare any inspector observed weakness with those identified by the licensee in order to verify whether the licensee was properly identifying deficiencies. The inspectors completed one sample, as defined in IP 71114.06.

b. Findings

No findings were identified.

OTHER ACTIVITIES

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

a. Inspection Scope

The inspectors sampled licensee submittals for the six PIs listed below for the period from July, 2015 through June, 2016 for both Unit 1 and Unit 2. Definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Indicator Guideline, Revision 6, were used to determine the reporting basis for each data element in order to verify the accuracy of the PI data reported during that period.

Cornerstone: Mitigating Systems

- Mitigating Systems Performance Index: Emergency AC Power
- Mitigating Systems Performance Index: High Pressure Injection System
- Mitigating Systems Performance Index: Heat Removal System (AFW)
- Mitigating Systems Performance Index: Residual Heat Removal System
- Mitigating Systems Performance Index: Cooling Water System
- Safety System Functional Failures

The inspectors reviewed portions of the operations logs and raw PI data developed from monthly operating reports and discussed the methods for compiling and reporting the PIs with engineering personnel. The inspectors also independently calculated selected reported values to verify their accuracy and compared graphical representations from the most recent PI report to the raw data to verify that the data was correctly reflected in the report. Specifically for the Mitigating Systems Performance Index (MSPI), the inspectors reviewed the basis document and derivation reports to verify that the licensee was properly entering the raw data as suggested by NEI 99-02. For Safety System Functional Failures, the inspectors also reviewed Licensee Event Reports (LERs) issued during the referenced timeframe. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Daily Review

a. Inspection Scope

As required by Inspection Procedure 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This was accomplished by reviewing the description of each new CR and attending daily management review committee meetings.

b. Findings and Observations

No findings were identified.

.2 Annual Follow-up of Selected Issues: Loss of essential air Issue

a. Inspection Scope

The inspectors conducted a detailed review of condition report (CR) 1187595, unplanned isolation of essential air header B.

The inspectors evaluated the following attributes of the licensee's actions:

- complete and accurate identification of the problem in a timely manner
- evaluation and disposition of operability and reportability issues
- consideration of extent of condition, generic implications, common cause, and previous occurrences
- classification and prioritization of the problem
- identification of root and contributing causes of the problem
- identification of any additional condition reports
- completion of corrective actions in a timely manner

Documents reviewed are listed in the attachment.

b. Findings and Observations

No findings were identified.

.3 Annual Follow-up of Selected Issues: CAP Effectiveness within the Training Program

a. Inspection Scope

The inspectors conducted a detailed review of various CRs that dealt with a variety of training issues. The inspectors were particularly interested in examples of inappropriate closure of CRs. The numerous CRs are listed in the attachment.

The inspectors evaluated the following attributes of the licensee's actions:

- complete and accurate identification of the problem in a timely manner
- evaluation and disposition of operability and reportability issues
- consideration of extent of condition, generic implications, common cause, and previous occurrences
- classification and prioritization of the problem
- identification of root and contributing causes of the problem
- identification of any additional condition reports
- completion of corrective actions in a timely manner

This constitutes a partial sample of the Annual Follow-up of selected issues. Documents reviewed are listed in the attachment.

b. Findings and Observations

No findings were identified.

4OA3 Follow-up of Events and Notices of Enforcement Discretion

.1 (Closed) Licensee Event Report (LER) 050000327, 328/2016-002-00, 01, High Pressure

Fire Protection System Isolation Results in Significant Loss of Fire Protection Capability

a. Inspection Scope

On March 30, 2016 the licensee discovered that a significant portion of the Fire Suppression system was isolated due to a clearance error. Following this discovery, the header was subsequently returned to service. The header was out-of-service for approximately 41 hours. This event is discussed in more detail in Section 4OA5. The event was documented in the licensee corrective action program as CR 1155763.

The inspectors reviewed the LERs, CR and Root Cause Evaluation (RCE) to verify that the cause of the loss of fire suppression was identified and that corrective actions were appropriate. The cause of loss of suppression water was due to an expanded clearance that isolated the fire pumps from the main fire suppression system. The RCE also noted a lack of ownership of the fire system components. The inspectors concluded that the licensee's corrective actions were appropriate, including the development of procedures and the clarification of the ownership of fire operating systems and requirements.

The inspectors discussed the trip with operations, engineering, and licensee management personnel to gain an understanding of the event and assess follow-up actions. The inspectors reviewed operator actions taken to determine whether they were in accordance with licensee procedures and TS, and reviewed unit and system indications to verify whether actions and system responses were as expected and designed. The inspectors verified that timely notifications were made in accordance with 10 CFR 50.72, that licensee staff properly implemented the appropriate plant procedures, and that plant equipment performed as required. These LERs are closed.

b. Findings

One finding was identified. See Section 4OA5.

.2 (Closed) Licensee Event Report (LER) 050000328/2015-002-00, Unanalyzed Condition due to Inoperable Containment Recirculation Drains

a. Inspection Scope

On November 10, 2015, two cold weather suits were inadvertently dropped into the equipment pit portion of the Sequoyah Nuclear Plant Unit 2 reactor cavity, resulting in two recirculation drains being declared inoperable. Following this discovery, both suits were captured and removed from the equipment pit. Plant conditions were restored to normal within the allowed action times and no plant shutdown was required. The event was documented in the licensee corrective action program as CR 1103003.

The inspectors reviewed the LER, CR and Apparent Cause Evaluation to verify that the cause of the inoperable containment recirculation drains was identified and that corrective actions were appropriate.

The cause of the inoperable containment recirculation drains was due maintenance craft failing to identify and mitigate potential hazards and risks before conducting work with cold weather suits in containment while in Modes 1-4. The inspectors concluded that the licensee's corrective actions were appropriate, including adding additional risk mitigation strategies to the containment access control procedure.

The inspectors discussed the event with maintenance, engineering, and licensee management personnel to gain an understanding of the event and assess follow-up actions. The inspectors reviewed operator actions taken to determine whether they were in accordance with licensee procedures and TS, and reviewed unit and system indications to verify whether actions and system responses were as expected and designed. The inspectors verified that timely notifications were made in accordance with 10 CFR 50.72, that licensee staff properly implemented the appropriate plant procedures, and that plant equipment performed as required. This LER is closed.

b. Findings

No findings were identified.

.3 (Closed) Licensee Event Report (LER) 050000327/2016-001-00, Automatic Safety Injection (SI) due to Low Steam Line Pressure on Loop 2 Main Steam

a. Inspection Scope

On February 9, 2016, Unit 1 experienced an automatic SI due to low steam pressure on loop 2. At the time of the event the unit was in Mode 3 and the operations were attempting to warm up the main steam lines by bypassing around the main steam isolation valves (MSIV). All required safety systems started and operated as required. Heat removal was via the auxiliary feed water pumps and the atmospheric relief valves. The operators executed emergency operating procedure, E-0, "Reactor Trip or Safety Injection," and quickly determined that an SI was not required and took actions in accordance with the emergency procedure, ES 1.1, "SI Termination" to reset SI and reestablish normal charging and letdown. The event was documented in the licensee corrective action program as CR 1135308.

The inspectors reviewed the LERs, CR and Root Cause Evaluation (RCE) to verify that the cause of the safety injection signal was identified and that corrective actions were appropriate. The cause of the safety injection was attributed to a rapid depressurization of the main steam (MS) header upstream of the MSIVs. The depressurization was due to the fact that the MS header had become full of water rather than steam due to operation for a prolonged period in Mode 3 with the MSIVs closed. The inspectors concluded that the licensee's corrective actions were appropriate, including the development of procedures to address operation in Mode 4 and above with the MSIVs closed.

The inspectors discussed the trip with operations, engineering, and licensee management personnel to gain an understanding of the event and assess follow-up actions. The inspectors reviewed operator actions taken to determine whether they were in accordance with licensee procedures and TS, and reviewed unit and system indications to verify whether actions and system responses were as expected and designed. The inspectors verified that timely notifications were made in accordance with 10 CFR 50.72, that licensee staff properly implemented the appropriate plant procedures, and that plant equipment performed as required. This LER is closed.

b. Findings

One finding was previously identified. See Sequoyah Integrated Inspection report 05000327, 328/2016001.

.4 (Closed) Licensee Event Report (LER) 05000327/2016-005-00, Hydrogen Mitigation System Train 'A' Inoperable Longer than Allowed by Technical Specifications

a. Inspection Scope

On June 7, 2016, at 0914 Eastern Standard Time , the licensee noted that a breaker which powered 2 of the 34 hydrogen igniters on Unit 1 'A' train hydrogen mitigation system (HMS) was in the open position contrary to the normal breaker alignment. Since one additional igniter had been declared out-of-service on March 8, 2016, this left 31 of 34 igniters operable on train 'A'. There are two trains of HMS, 'A' and 'B', both of which contain 34 igniters for a total of 68 igniters. Technical Specification (TS) Limiting Condition for Operation (LCO) 3.6.8, HMS, requires a minimum of 33 of 34 igniters to be operable per train. This LCO was immediately entered at the time of discovery. Two minutes later the affected breaker was closed and the LCO was exited. A past operability evaluation (POE) noted that the last time this affected breaker panel was accessed was on March 8, 2016. The licensee assumed that the breaker had been inadvertently left open for approximately 91 days. LCO 3.6.8 has an action time of 7 days, else the unit shall be placed in Mode 3. Thus, this LER was required pursuant to 10CFR50.73 (a)(2)(i)(B) as a condition prohibited by the plant's TS. The licensee documented the issue in CR 1179126, which included an apparent cause evaluation.

The inspectors discussed the event with operations, maintenance, engineering, and licensee management personnel to gain an understanding of the conditions leading up to the event and assess licensee actions taken following the event. Additionally, the inspectors reviewed the apparent cause evaluation report to assess the detail and thoroughness of the evaluation and the adequacy of the proposed corrective actions. The licensee could not identify the instance where the subject breaker was placed in the "OFF" position and concluded it was accidently bumped or jarred when the cabinet was opened on March 8.

The inspectors reviewed CR 1179126 to verify that the cause of the degraded HMS was identified and whether corrective actions were appropriate. The licensee's apparent causal evaluation performed an extent of condition to ensure all breakers in the HMS system were properly configured. The inspectors concluded that the licensee's corrective actions to this event were appropriate, including the performance of a past operability evaluation. This LER is closed.

b. Findings

Introduction. A self-revealing Green NCV of TS 3.6.8 was noted for the licensee's failure to restore an inoperable train of HMS to service within the required completion time 7 days. In addition, the licensee failed to be in Mode 3 within the following 6 hours following the failure to meet the 7 day action time. The licensee estimated the entire exposure time to be approximately 91 days.

Description. On June 7, during the performance of procedure 1-SI-EIV-268-305.A, "Hydrogen Mitigation System Operability Current Check," Rev. 4, the craft personnel noted that circuit breaker, 1-BKRB-268-YA/129A, breaker 11, was open. This procedure is used to verify the operability of the HMS pursuant to Surveillance requirement 3.6.8.1 and 3.6.8.2 This breaker supplied the power to two hydrogen ignitors, 124 and 129. This was brought to the attention of the operations crew and the 'A' train HMS was declared out-of-service at 0914. The operations crew directed closure of the breaker and the 'A' train HMS was restored to operable status at 0916.

A subsequent POE determined that the last time the cabinet was accessed was on March 8 in order to replace ignitor 128. Breaker 11 was noted to be in the "OFF" position and not the "TRIP" position. The POE concluded that the breaker was accidentally bumped and moved from its normal ("ON") position. The POE established the exposure time of 91 days.

The three inoperable igniters (102, 124, and 129) were located at the following elevations and azimuths:

Igniter	Elevation (feet)	Azimuth (degrees)
102	693	135
124	721	94
129	721	20

The inspectors reviewed the design Basis document, SQN-DC-V-26.1, "Combustible Gas Control Program," Revision 5 and noted that all three affected igniters were located in the general area of lower containment. Igniter 102 was located near the reactor cavity wall exterior. Igniter 124 was located near the lower end of the pressurizer. Igniter 129 was located near Steam Generator loop #3. None of the affected igniters was located in dead ended compartments nor the upper containment compartment. The general area of lower containment contains 22 igniters and thus 18 remained functional.

This event was entered into the licensee's corrective action program as CR 1179126. The licensee performed an apparent cause evaluation, which determined that the breaker was accidently bumped during maintenance on March 8.

<u>Analysis.</u> The licensee's failure to preclude an inoperable HMS train for more than 7 days without a subsequent plant shutdown was a performance deficiency. Specifically, during plant maintenance on March 8, a breaker was accidently placed in the 'OFF" position and left in this condition for 91 days. This disabled 2 hydrogen igniters (129 and 124). Concurrently, igniter 102 was inoperable due to a previous failure. This left only 31 of the 34 of the train 'A' ignitors operable for 91 days and was a condition prohibited by TS. The inspectors evaluated this issue in accordance with the NRC's significance determination process (SDP). This finding was determined to be greater than minor because it was associated with the Configuration Control attribute of Barrier Integrity cornerstone and adversely affected the cornerstone's objective to ensure the structural integrity of the containment boundary. Specifically, the finding challenged containment integrity as hydrogen igniters have a high risk significance in ice condenser style containments. Using IMC 0609.04, Initial Characterization of Findings and IMC 0609 Appendix A, Exhibit 3 – Barrier Screening Questions, the finding required analysis using MC 0609, Appendix 'H', "Containment Integrity Significance Determination Process," as the finding involved an actual reduction in function of hydrogen igniters in containment.

According to Appendix H, the finding represented a Type B finding as it did not directly affect the core damage frequency. The finding was then processed under Section 6 using a phase 2 analysis. The inspectors performed the phase 2 analysis using Sec 6.2 of Appendix H as the finding was associated with hydrogen igniter in an Ice Condenser style containment. The inspectors determined that the failure of three igniters did not result in a loss of coverage in two adjacent compartments. Thus the inspectors screened this finding to Green. The cause of this finding was determined to have a cross-cutting aspect in the Human Performance component, where individuals failed to implement appropriate error reduction tools. [H.12].

Enforcement. Unit 1 TS LCO 3.6.8 requires that if an HMS train is inoperable for more than 7 days then the unit shall be placed in Mode 3 in the following 6 hours. Contrary to the above, the Unit 1 ‘A’ train HMS system was inoperable from March 8, 2016 to Jun 7, 2016 or approximately 91 days while the unit remained in Mode 1. Because the finding was of very low safety significance and has been entered into the licensee’s CAP as CR 1179126, this violation is being treated as an NCV, consistent with section 2.3.2.a of the NRC Enforcement Policy: NCV 05000327/2016003-01, Hydrogen Mitigation System Inoperable Longer than Allowed by Technical Specifications.

4OA5 Other Activities

(Closed) Apparent Violation 05000327, 328/2016002-01, “Isolation of Fire Suppression System to a Significant Portion of the Plant Site.

a. Inspection Scope

The inspectors performed a detailed review of a risk analysis associated with the isolation of the Sequoyah fire suppression header that was documented in Sequoyah Integrated Inspection report 05000327, 328/2016002-01. The inspectors concluded that the issue was of very low safety significance as documented below. Hence apparent violation 05000327, 328/2016002-01 is now closed.

b. Findings

Introduction. A self-revealing Green NCV of the facility’s operating license was identified for the licensee’s failure ensure the fire suppression system was operable and capable of suppressing fires. Specifically, the licensee inadvertently disabled the High Pressure Fire Protection (HPFP) water system in excess of 24 hours and concurrently failed to implement required compensatory measures for the disabled header contrary to the approved fire protection report (FPR).

Description On March 23, 2016, the licensee established a clearance on the high pressure fire water system in order to perform planned maintenance in a valve pit. Subsequently, it was determined that the clearance boundary was inadequate in that one of the boundary valves leaked by the seat. On March 29, the clearance boundary was expanded in order to reduce any leakage into the affected work area. On March 30, during routine fire operation testing, operators noted that water was not available at a hose station near the emergency diesel generator (EDG) building. Subsequent investigation revealed the expanded clearance had isolated the main fire suppression system from the fire pumps and fire tanks. Thus, if a fire had occurred, no suppression would have been available to most of the plant site. The affected areas included the control building, turbine building, auxiliary building, and the EDG building. Upon discovery, the licensee implemented the requirements of the fire protection report (FPR). This, included fire operating requirement (FOR), 14.2.1, 14.3.1, and 14.5.1 for fire water suppression system, spray/sprinkler systems, and fire hose stations, respectively. On March 31, full functionality of the HPFP system was restored and operations exited the requirements of the FPR. The exposure time for the disabled HPFP system was approximately 41 hours.

This event was entered into the licensee's corrective action program as CR 1155763. A root cause team was formed in order to determine the cause of the fire header isolation. The team concluded that the direct cause of the failure to comply with the FORs was due to an inadequate review of the system impact caused by the expanded clearance boundary. The root cause was attributed to a shift in responsibility for fire compliance to the fire operations personnel rather than maintaining the responsibility within the operations group. Concurrently with the establishment of a root cause team, the licensee began an effort to appropriately analyze the risk significance of the event.

<u>Analysis</u> The licensee's failure to properly assess the system impact of a clearance revision for the suppression header and enter the required FPR Operating Requirement Action was a performance deficiency. Specifically, the licensee expanded a clearance that isolated the HPFP suppression header to the control building, auxiliary building, turbine building, diesel generator building, and both containments without conducting reviews required per NPG-SPP-10.2, "Clearance Procedure to Safely Control Energy." The performance deficiency was determined to be more than minor because it was associated with the protection against external events (fire) attribute of the mitigating systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inability to pressurize the HPFP system from either the electric or diesel-driven fire pumps rendered the fire suppression system inoperable.

The inspectors performed an initial screening of the finding using NRC Inspection Manual Chapter (IMC) 0609, Attachment 4, Phase 1 – "Initial Screening and Characterization of Findings," which affected the mitigating systems cornerstone and required further evaluation in accordance with IMC 0609 Appendix F, Attachment 1, "Fire Protection SDP Phase 1 Worksheet," as the finding involved the inability of a fixed fire protection system to confine a fire. In accordance with Attachment 1, the finding was assigned to section 1.4.7 "Fire Water Supply," where it was determined that due the large number of affected buildings and areas, it was unknown whether the reactor would be able to reach and maintain safe shutdown (SSD) given a complete loss of suppression. Additionally, using Attachment 2, the degradation of the suppression system was determined to be "high" as the system was unable to be pressurized from the installed plant fire pumps. Given the potential effect on SSD and the "high" degradation of the HPFP system, the finding was evaluated using Task 1.4.7, "Fire Water Supply," as described in Attachment 1. Due to the large number of areas affected, the inspectors determined that the delta CDF was greater than 1E-06 and thus required a phase 2 analysis to reach a significance characterization. The finding did not present an immediate safety concern because the fire suppression system was quickly returned to service upon discovery of the clearance error.

The inspectors noted that Appendix 'F' of IMC 0609 discusses SSD findings that affect multiple areas. The Phase 2 SDP should only be applied when the finding can be identified within a specific fire area. For findings with plant-wide consequences, a Phase 3 SDP assessment should be performed. Thus, due to the large number of areas affected (Auxiliary building, turbine building, EDG building, etc.) in this particular finding, a Phase 2 analysis was deemed to be an inappropriate tool.

Based on the complexities of this particular event, the inspectors concluded that Appendix M, "Significance Determination Process Using Qualitative Criteria," of IMC 0609 should be performed in lieu of a Phase 3 analysis. This was based on the fact that existing SDP methods and tools were not adequate to determine the significance of this finding within the established SDP timeliness goals. Under appendix M, the Senior Reactor Analyst (SRA) performed an initial bounding evaluation using qualitative methods. The licensee submitted an extensive, detailed screening analysis that estimated an upper bound for the risk of the finding. The result was less than 1E-6. The SRA performed a review of this screening analysis as part of this SDP evaluation. The SRA reviewed the submitted methodology. In addition, selected numeric values used in the calculations were validated. The SRA also reviewed the comments and resolutions of the independent engineering review the licensee had conducted of the results. In addition to the SRA review, the resident inspectors performed an independent review of the licensee's estimation of the success of actions used to recover the isolated fire header. To the extent reviewed, the methodology and results were determined to be acceptable for use in this SDP review of this Performance Deficiency. The SRA concurred with the submitted results of the licensee's screening analysis, and has determined the finding to be GREEN.

Using Inspection Manual Chapter 0310, "Aspects within the Cross-Cutting Areas," the inspectors identified a cross-cutting aspect in the Procedural Adherence component of the Human Performance area, because the licensee failed consider the effect that changing a clearance order could have on the operability of the fire suppression system. [H.8]

Enforcement Facility operating licenses DPR-77 and DPR-79 conditions 2.C.(16) and 2.C.(13), respectively, state that TVA shall implement and maintain in effect all provisions of the approved fire protection program referenced in Sequoyah Nuclear Plant's Final Safety Analysis Report as approved in applicable NRC Safety Evaluation Reports. The Sequoyah Fire Protection Report Part II, Section 14.2, "Fire Suppression Water," FOR 14.2.1 requires, that with no fire pump functional, then establish contingency measures and restore the system to operable status within 24 hours or place the unit in Mode 3 within 7 hours, Mode 4 with 13 hours, and Mode 5 within 37 hours. The Sequoyah Fire Protection Report Part II, Section 14.3, "Spray and/or Sprinkler Systems," FOR 14.3.1 requires, that with one or more sprinkler systems inoperable, then establish fire watches within one hour. The Sequoyah Fire Protection Report Part II, Section 14.5, "Fire Hose Stations," FOR 14.5.1 requires, that with one or more required fire hose stations nonfunctional, then within 1 hour, route an equivalent capacity fire hose to the unprotected area.

Contrary to the above, from March 29, 2016 to March 31, 2016, or approximately 41 hours, the licensee isolated the HPFP header from the normal sources of water that effectively disabled all fire pumps, suppression system, and hose stations to various safety-related areas without the implementation of any contingency measures such as the prestaging of backup water supplies and hoses, as well as the establishment of hourly fire watches. Upon discovery of the clearance error, the system was restored to a functional status. The licensee entered the issue into their CAP as CR 1155763. Because the finding was of very low safety significance and has been entered into the licensee's CAP as CR 1155763, this violation is being treated as an NCV, consistent with section 2.3.2.a. of the NRC Enforcement Policy: NCV 05000327, 328/2016003-02, Isolation of Fire Suppression System to a Significant Portion of the Plant Site.

4OA6 Meetings, Including Exit

.1 Exit Meeting Summary

On October 21, 2016, the resident inspectors presented the inspection results to Mr. Pratt and other members of his staff, who acknowledged the findings. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Regulatory Performance Meeting

On October 21, 2016, a Regulatory Performance Meeting was held with Mr. Pratt and other members of the licensee's staff. The licensee staff discussed implementation of corrective actions associated with the recent IP 95001 inspection documented in NRC report 05000327/2016008. NRC staff reviewed the Reactor Oversight Process timeline for closing corrective actions and related inspection findings.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

D. Dimopoulos, Director Plant Support
M. Halter, Senior Manager Radiation Protection
M. Henderson, Manager Engineering Programs
J. Johnson, Program Manager Licensing
A. Little, Senior Manager Nuclear Site Security
M. Lovitt, Chemistry Manager
T. Marshall, Director Operations
M. McBrearty, Licensing Manager
W. Pierce, Director Engineering
P. Pratt, Plant Manager and Acting Site Vice President
M. Rasmussen, Director Maintenance
J. Rolph, Radiation Protection Technical Support Superintendent
K. Smith, Director Training

NRC personnel
A. Hon, Project Manager, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000327, 328/2016003-01	NCV	Hydrogen Mitigation System Inoperable Longer than Allowed by Technical Specifications (Section 4OA3)
05000327, 328/2016003-02	NCV	Isolation of Fire Suppression System to a Significant Portion of the Plant Site (Section 4OA5)

Closed

05000327, 328/2016002-01	AV	Isolation of Fire Suppression System to a Significant Portion of the Plant Site (Section 4OA5)
050000327, 328/2016-002-00, 01	LER	High Pressure Fire Protection System Isolation Results in Significant Loss of Fire Protection Capability (Section 4OA3)
050000328/2015-002-00	LER	Unanalyzed Condition due to Inoperable Containment Recirculation Drains (Section 4OA3)
050000327/2016-001-00	LER	Automatic Safety Injection due to Low Steam Line Pressure on Loop 2 Main Steam (Section 4OA3)
050000327/2016-005-00	LER	Hydrogen Mitigation System Train ‘A’ Inoperable Longer than Allowed by Technical Specifications (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Section R01: Adverse Weather Protection

Procedures
AOP-N.02, Tornado Watch/Warning, Revision 35

Section R04: Equipment Alignment

Partial System Walkdowns

Procedures
0-GO-1, Unit Startup from Cold Shutdown to Hot Standby, Revision 79
0-GO-7, Unit Shutdown from Hot Standby to Cold Shutdown, Revision 79
0-GO-13, Reactor Coolant System Drain and Fill Operations, Revision 88
0-SO-74-1, Residual Heat Removal System, Revision 99
0-SO-30-18, Auxiliary Building Gas Treatment System, Revision 15
0-SO-30-10, Auxiliary Building Ventilation System, Revision 62
0-SI-OPS-030-021.A, B, ABGTS Train A/B Operability Test, Revision 9
1, 2-SO-63-5, Emergency Core Cooling System, Revision 68
1-SO-62-1, Chemical and Volume Control System, Revision 71
2-SO-62-1, Chemical and Volume Control System, Revision 71

Other documents
0-47W810-1, Flow Diagram Residual Heat Removal System
1, 2-47W611-74-1, Mechanical Logic Diagram Residual Heat Removal
0-45N779-9, 480V Shutdown Power Schematic
0-45N779-11, 480V Shutdown Power Schematic
0-45N779-12, 480V Shutdown Power Schematic
0-45N674, RHR Schematic Diagram
1, 2-47W611-63-5, Mechanical Logic Diagram Residual Heat Removal
0-45N657-8, Wiring Diagrams Separation and Misc Aux Relays
0-45N765-13, Wiring Diagrams 6900v Shutdown Aux Power
SQN-DC-V-13.9.4, Auxiliary Building Secondary Containment Ventilation System
FSAR 6.2.1, Containment Functional Design (ABSCE)
FSAR 6.2.3, Auxiliary Building Gas Treatment System

Complete System Walkdown

Procedures
0-SO-90-1, Liquid Process Radiation Monitors, Revision 27
1-SO-90-1, Liquid Process Radiation Monitors, Revision 13
2-SO-90-1, Liquid Process Radiation Monitors, Revision 11

0-SO-90-2, Gaseous Process Radiation Monitoring System, Revision 28

1-SO-90-2, Gaseous Process Radiation Monitoring System, Revision 44
2-SO-90-2, Gaseous Process Radiation Monitoring System, Revision 44
0-SO-90-5, Area Radiation Monitors, Revision 10
1-SO-90-2, Area Radiation Monitors and MCR Radiation Instrumentation, Revision 19
2-SO-90-2, Area Radiation Monitors and MCR Radiation Instrumentation, Revision 19

Drawing
1, 2-47W610-90-1, Mechanical Control Diagram Radiation Monitoring System, Revision 41
1, 2-47W610-90-2, Mechanical Control Diagram Radiation Monitoring System, Revision 78

Section R05: Fire Protection

Procedures
FPDP-1, Conduct of Fire Protection, Revision 7
0-PI-FPU-317-299.W, Att. 8, Shift Check List, Revision 42
NPG-SPP-18.4.7, Control of Transient Combustibles, Rev. 7
NPG-SPP-05.5 Environmental Control, Rev.1
0-SI-FPU-410-703.0, Inspection of FPR Required Fire Doors, Rev. 6
SQN-FPR-Part-II, SQN Fire Protection Report Part II – Fire Protection Plan, Revision 35

Other documents
AUX-0-653-00, Fire Protection Pre-Fire Plans Auxiliary Building - El. 653, Revision 9
AUX-0-669-02, Fire Protection Pre-Fire Plans Auxiliary Building - El. 669 (Unit 2 side), Revision 9
AUX-0-669-01, Fire Protection Pre-Fire Plans Auxiliary Building - El. 669 (Unit 1 side), Revision 8
AUX-0-669-00, Fire Protection Pre-Fire Plans Auxiliary Building - El. 669, Revision 4
AUX-0-669-03, Fire Protection Pre-Fire Plans Auxiliary Building - El. 669 (Common Area), Revision 7
AUX-0-669-04, Fire Protection Pre-Fire Plans Auxiliary Building - El. 669 (ERCW Tunnels), Revision 6

Section R11: Licensed Operator Requalification

Other documents
SEG: S-129, ATWS/SBLOCA, Revision 0

Section R12: Maintenance Effectiveness

Procedures
TI-4, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting – 10CFR50.65, Revision 29

Section R13: Maintenance Risk Assessments and Emergent Work Evaluation

Procedures
NPG-SPP-07.3, Work Activity Risk Management Process, Revision 19
NPG-SPP-07.2.4, Forced Outage or Short Duration Planned Outage Management, Revision 6
NPG-SPP-07.2, Outage Management, Revision 5
GOI-6, Apparatus Operations, Revision 172

Section R15: Operability Evaluations

Procedures
NEDP-22, Operability Determinations and Functional Evaluations, Rev. 17
OPDP-8, Operability Determination Process/Limiting Conditions for Operation Tracking, Rev. 21
NPG-SPP-03.5, Regulatory Reporting Requirements, Revision 13

CRs
1169888, Test header Alignment to ECCS Header potentially causes both trains to be rendered inoperable (POE)
1197233, Emergency diesel generator 1B-B cooling water level low
1198440 and 1200028, EGTS Operability Determination
1179126, H2 Igniter breaker found open

Section R18: Plant Modifications

Procedures
NPG-SPP-09.3, Plant Modifications and Engineering Change Control, Revision 21
NPG-SPP-09.4, 10 CFR 50.59 Evaluations of Changes, Tests, and Experiments, Revision 10
NPG-SPP-09.5, Modifications Temporary Configuration Changes, Revision 9

Other documents
SQN-0-2016-065-001 – Disabling the EGTS Annulus differential pressure automatic swap over circuits for Unit 1 and Unit 2

Section R19: Post Maintenance Testing

Procedures
MMDP-1, Maintenance Management System, Revision 31
NPG-SPP-06.14, Guidelines for Planning and Execution of Troubleshooting Activities, Rev.01
NPG-SPP-06.5, Foreign Material Control, Revision 9
NPG-SPP-06.1, Work Order Process Initiation, Revision 5
NPG-SPP-06.3, Pre-/Post-Maintenance Testing, Revision 1
NPG-SPP-06.9, Testing Programs, Revision 1
NPG-SPP-06.9.1, Conduct of Testing, Revision 10
NPG-SPP-06.9.3, Post-Modification Testing, Revision 6

Work Orders
117862482, Replacement of pressure relief valve (2-VLV-067-1521) for the auxiliary control air compressor B
116690150, 2A Pressurizer Heater relay replacement
118035577, ISI Accumulator Tank 1 level drifting high
118005098, Diesel Generator starting air compressor relief lifting
118121022, Replacement of shutoff valve (SQN-0-VLV-082-0548-1B2) on the 1B2 EDG

Section R22: Surveillance Testing

Procedures
NPG-SPP-06.9.1, Conduct of Testing, Revision 10
0-SI-SXV-072-266.0, ASME Code Valve Testing, Revision 14
1-SI-SXP-074-201.A. Residual Heat Removal Pump 1A-A Performance Test, Revision 18

0-SI-OPS-085-011.0, Reactivity Control Systems Moveable Control Assemblies, Revision 37
2-SI-SXP-074-201.B, Residual Heat Removal Pump 2B-B Performance Test, Revision 17

Section 1EP6: Drill Evaluation

Procedures
EPIP-1, Emergency Plan Classification Matrix, Revision 52
EPIP-2, Notification of Unusual Event, Revision 35
EPIP-3, Alert, Revision 37
EPIP-4, Site Area Emergency, Revision 38
EPIP-5, General Emergency, Revision 47

Section 4OA1: Performance Indicator Verification

Procedures
NPG-SPP-02.2, Performance Indicator Program, Revision 7
NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 7

Section 4OA2: Identification and Resolution of Problems

Procedures
NPG-SPP-03.1, Corrective Action Program, Revision 7

CRs	CRs	CRs	CRs	CRs	CRs
1178985	1118912	896152	800983	569984	393838
1178609	1095026	896151	798054	569854	238201
1169359	968477	891204	720828	443197	224548
1146818	968418	869153	632868	433743	
1138264	960854	824032	621922	405141	

SRs
891204
891220

Section 4OA3: Event Followup

Procedures
NPG-SPP-10.2, Clearance Procedure to Safely Control Energy, Revision 16
0-SO-32-2, Auxiliary Compressed Air, Revision 20

LERs
050000327, 328/2016-002-00 and 01, High Pressure Fire Protection System Isolation Results in Significant Loss of Fire Protection Capability
050000328/2015-002-00, Unanalyzed Condition due to Inoperable Containment Recirculation Drains
050000327/2016-001-00, Automatic Safety Injection due to Low Steam Line Pressure on Loop 2 Main Steam
050000327/2016-005-00, Hydrogen Mitigation System Train ‘A’ Inoperable Longer than Allowed By Technical Specifications

CRs
1187595
1179126
1155763
1135308
1103003

Other documents
Level 2 Evaluation for CR 1188485
Clearance 0-32-0564, Date 6/30/2016

Section 4OA5: Other Activities

Other documents
PRA Evaluation SQN 0-16-091, High Pressure Fire Protection Isolation, Rev. 0

ACRONYMS

AC	alternating current
ABGTS	auxiliary building gas treatment system
ADAMS	Agencywide Documents Access and Management System
AFW	auxiliary feedwater
AOP	abnormal operating procedure
ARV	atmospheric relief valves
CA	corrective actions
CAP	corrective action program
CCP	centrifugal charging pump
CDE	cause determination evaluation
CFR	Code of Federal Regulations
CR	condition report
ECCS	emergency core cooling system
EDG	emergency diesel generator
EN	event notification
ERCW	essential raw cooling water
EST	Eastern Standard Time
F	Fahrenheit
FOR	fire operating requirement
FPR	fire protection report
GL	general letter
HMS	hydrogen mitigation system
HPFP	high pressure fire protection
IMC	inspection manual chapter
IP	inspection procedure
LCO	limiting condition for operation
LER	licensee event report
MS	main steam
MSIV	main steam isolation valves
MSPI	mitigating systems performance indicator
NCV	non-cited violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OOS	out-of-service
PAR	protective action recommendation
PI	performance indicator program
POE	past operability evaluation
RCE	root cause evaluation
RCS	reactor coolant system
RHR	residual heat removal
RTP	rated thermal power
SDP	significance determination process
SI	safety injection
SRA	senior reactor analyst
SRs	service requests
SSCs	structure, system, or components
SSD	safe shutdown
TS	technical specification
TVA	Tennessee Valley Authority

U1	Unit 1
U2	Unit 2
UFSAR	updated final safety analysis report
WO	work order