UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-338/94-05 and 50-339/94-05

Licensee: Virginia Electric and Power Company
5000 Dominion Boulevard
Glen Allen, VA 23050

Docket Nos.: 50-338 and 50-339

License Nos.: NPF-4 and NPF-7

Facility Name: North Anna 1 and 2

Inspection Conducted: February 20 through March 19, 1994

Inspectors:

L. W. Garner For — 4-7-94
R. D. McWhorter, Senior Resident Inspector — Date Signed

L. W. Garner For — 4-7-94
D. R. Taylor, Resident Inspector — Date Signed

Approved by: G. A. Belisle — 4/7/94
G. A. Belisle, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant status, operational safety verification, maintenance observations, surveillance observations, Licensee Event Report followup, and action on previous inspection items. Licensee backshift activities were inspected on February 23, 24, and 27, and March 2, 5, 11, 13, 14 and 16, 1994.

Results:

Plant Operations functional area

A running service water pump was inadvertently isolated while performing a quarterly surveillance test. Operators quickly identified and corrected the error. Technical Specification requirements were met during the period the pump was inoperable (paragraph 3.b).

Maintenance functional area

Major maintenance activities were performed in attempts to repair continuing problems with water intrusion into the Unit 2 turbine drive auxiliary feedwater pump lubricating oil. Unanticipated problems during this maintenance resulted in a request from the licensee to the NRC for enforcement discretion from Technical Specification 3.7.1.2 action requirements. The enforcement discretion was granted, and the pump was returned to operable status. However, the problem was not fully corrected, and the licensee was planning additional corrective actions (paragraph 4).

The licensee demonstrated a strong safety initiative by establishing a review to verify fire protection surveillances were properly implemented. An Inspector Followup Item was opened to evaluate the review's results (paragraph 5.c).

Engineering functional area

An Engineering Work Request for a flow switch setpoint change did not consider the effect of a loss of off-site power (paragraph 3.a).

An Inspector Followup Item was identified to review equipment and radiological consequences due to single failure potential in the Safeguards Area Ventilation System (paragraph 5.b).

Plant Support functional area

A strength was identified in the licensee's Deficiency Report process. Overall, the process was found to contribute to maintaining plant safety (paragraph 3.c).

REPORT DETAILS

1. Persons Contacted

<u>Licensee Employees</u>

L. Edmonds, Superintendent, Nuclear Training
C. Funderburk, Superintendent, Outage and Planning
*J. Hayes, Superintendent, Operations
D. Heacock, Superintendent, Station Engineering
#J. Hegner, Supervisor, Licensing
*G. Kane, Station Manager
*P. Kemp, Supervisor, Licensing
*R. Jones, Supervisor, Quality
*J. Leberstien, Staff Engineer, Licensing
W. Matthews, Assistant Station Manager, Operations and Maintenance
J. O'Hanlon, Vice President, Nuclear Operations
D. Roberts, Supervisor, Station Nuclear Safety
*R. Saunders, Assistant Vice President, Nuclear Operations
D. Schappell, Superintendent, Site Services
R. Shears, Superintendent, Maintenance
J. Smith, Manager, Quality Assurance
A. Stafford, Superintendent, Radiological Protection
*#J. Stall, Assistant Station Manager, Nuclear Safety and Licensing

Other licensee employees contacted included managers, supervisors, operators, engineers, technicians, mechanics, security force members, and office personnel.

<u>NRC Personnel</u>

*R. McWhorter, Senior Resident Inspector
#D. Taylor, Resident Inspector

*Attended Exit Interview on March 25, 1994.
#Attended Exit Interview on April 7, 1994.

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Plant Status

Both Unit 1 and Unit 2 operated the entire inspection period at or near 100% power.

3. Operational Safety Verification (71707)

The inspectors conducted frequent control room tours to verify proper staffing, operator attentiveness, and adherence to approved procedures. The inspectors attended daily plant status meetings to maintain awareness of overall facility operations and reviewed operator logs to verify operational safety and compliance with TS. Instrumentation and safety system lineups were periodically reviewed from control room indications to assess operability. Frequent plant tours were conducted to observe equipment status, fire protection program implementation, radiological work practices, plant security, and housekeeping. DRs were reviewed to assure that potential safety concerns were properly reported and resolved.

a. Casing Cooling Flow Switch Failures

On February 16, 1994, the licensee identified that casing cooling flow switch 1-RS-FS-104B failed to trip during testing. This discovery followed problems identified on January 13, February 7, and February 14 when the licensee found that the other three casing cooling flow switches, 2-RS-FS-204A, 2-RS-FS-204B and 1-RS-FS-104A, tripped out-of-tolerance low during testing. These flow switches were designed to shut associated casing cooling pump discharge valves (1-RS-MOV-101A, B and 2-RS-MOV-201A, B) during a CDA if a low flow condition existed for 45 seconds. This function's purpose was to prevent containment sump water from reaching the environment via backflow if a pump failed or the casing cooling tank emptied.

The inspectors monitored the licensee's decision concerning reportability, since the February 16 event would have prevented automatic valve closure. After three SNSOC sessions, the licensee concluded that this condition was not reportable since the automatic function served as a backup to operator actions to isolate the pumps from containment and was not required by TS. Through a UFSAR, TS and DBD review, the inspectors verified that the failures were not reportable per 10 CFR 50.72 and 50.73.

At management's direction, maintenance and engineering personnel reviewed the failures and identified issues which could contribute to repeated problems with flow switch calibration. The flow switches were found to be subject to significant hydraulic shocks during pump starting which could have led to shifts in switch calibration. Additionally, the flow switch setpoint (10 feet H_2O) was found to be at the extreme low end of the switch's operating range (0-100 feet H_2O), which could have contributed to setpoint inaccuracy. The licensee planned actions to correct both problems. The licensee initiated installing snubbers (hydraulic dampers) for the flow switches to limit shocks during pump starts. Also, licensee engineering developed an EWR which approved a switch setpoint change to allow placing the actuation point in a more optimum place within the switch's operating range (40 feet H_2O). After a review and EWR approval by the SNSOC, the changes were initiated. Two switches then had snubbers installed, and one switch had a setpoint change made.

On March 17, the inspectors reviewed the licensee's engineering documentation to support the snubber installation changes. The inspectors found that the justification for snubber installation was based on an engineering memorandum which did not include an activity screening checklist or safety evaluation. The inspectors discussed this observation with plant management. Licensee management indicated that activity screening was not required because the snubber installation did not represent a true facility char since it would not change how the system functioned as des...ed in design documents. The inspectors evaluated this explanation and concluded that the licensee's interpretation was consistent with administrative requirements.

The activity screening checklist for the setpoint change EWR determined that a safety evaluation was not required. The inspectors reviewed the EWR's adequacy by reviewing applicable drawings and procedures, the UFSAR and the DBD. The inspectors determined and engineering personnel later confirmed that a loss of off-site power was not considered in the analysis. After power is restored, the casing cooling pumps start after a 35 second time delay. However, the 45 second time delay associated with the casing cooling flow switch starts as soon as bus power is restored. Consequently, for a CDA with loss of off-site power, only 10 seconds exist for flow to increase above the flow switch setpoint thereby preventing closure of the casing cooling pump discharge valves. Subsequent analyses by the licensee confirmed that premature closure of the pump discharge valves would not occur under this scenario. Considering timing relay tolerances, the installed snubber and the higher setpoint, a 0.13 second margin was available for the flow switch to sense flow before the flow switch timing circuit actuates to close the pump discharge valves. The licensee reviewed the test records for each 45 second time delay relay and found that all would actually take slightly longer than 45 seconds to respond. This provided additional margin; however, the licensee suspended snubber installation and setpoint changes on the remaining flow switches pending additional design reviews. Based on this information, the inspectors accepted the licensee's conclusions that the current configuration was acceptable for operation pending further design and change reviews.

The inspectors discussed the failure to evaluate the affect of a loss of off-site power in the EWR with licensee management. Management considered this as an "engineering error". As a result, an investigation team had been formed to review the problems and identify corrective actions. The EWR was inadequate in that it failed to evaluate the worst case scenario while addressing the acceptability of a change to flow switches. This was a weakness in engineering.

b. Inadvertent Service Water Pump Isolation

On March 3, 1994, the licensee identified that SW pump 1-SW-P-1B had been inadvertently isolated while performing 1-PT-75.2A, Service Water Pump (1-SW-P-1A) Quarterly Test, revision 20. During the test, the procedure required disabling and isolating SW pump 2-SW-P-1B. SW pump 2-SW-P-1B was placed in pull-to-lock as required by the procedure. Shortly thereafter, an auxiliary operator mistakenly shut the local discharge isolation valve, 1-SW-11, for SW pump 1-SW-P-1B, instead of valve 2-SW-13 for SW pump 2-SW-P-1B. The valve was shut for approximately five minutes before control room operators noted a high discharge pressure on the isolated but running pump and directed efforts to find and correct the problem. Although the isolated pump was the only pump running to supply the number two SW header, flow was maintained to both headers since, at the time, the two SW headers were cross-tied to supply containment coolers due to chilled water system maintenance.

The auxiliary operator's error resulted in inadvertently disabling two of the four SW pumps instead of one of the four as directed by the procedure. Each of the two disabled pumps were on a separate SW header. This placed the plant in a condition allowed by TS LCO 3.7.4.1, action b, which required that CC flow be throttled within one hour, and at least one SW pump returned to operable status within 72 hours. The inspectors verified that the licensee complied with the LCO action statement. However, the inspectors were concerned that inattention to detail by the operator in incorrectly identifying equipment being manipulated led to an unplanned plant degradation. This problem was mitigated by the fact that operators quickly identified and corrected the mistake.

The inspectors reviewed the licensee's response to the event. Licensee management directed that an HPES investigation be initiated to identify factors contributing to the operator's error and corrective actions. Additionally, the operator involved was coached by operations management, and an operations alert message concerning the event was placed in the Operation's LAN system. The inspectors were also aware of the licensee's extensive ongoing efforts to identify and reduce human performance errors at the facility and that this event would be integrated into that project. The inspectors concluded that the operator's error was receiving an appropriate attention level by licensee management and operations personnel.

c. Deficiency Report Program Review

During the inspection period, the inspectors reviewed the licensee's DR process. This review was prompted by the casing cooling flow switch problem (paragraph 3.a) and other issues. This review came simultaneously with an initiative by the licensee to change methods for identifying repeat DRs to management.

The casing cooling pump flow switch problem was an example of multiple DRs being written and evaluated as a repeat by this new initiative. The inspectors reviewed the threshold for DR submission and the process for DR tracking and resolution. The inspectors appraised the licensee's records for DR submission and the procedure governing DR submission, VPAP-1501, Station Deviation Reports, revision 3.

The inspectors found that licensee employees had an appropriately low threshold for DR submission. Also, the licensee had an adequate system for prioritizing DRs and was working to improve the classification process beyond the existing guidelines which were based on generic industry guidance. The inspectors concluded that the licensee's DR process was good since employees used DRs regularly to document plant problems, DRs were appropriately classified and tracked to resolution, and DRs were being used to identify repeat problems to management. Overall, the process was considered a strength that contributed to maintaining plant safety.

d. NRC Notifications

1) On February 23 and March 3, 1994, the licensee notified the NRC as required by 10 CFR 50.72 concerning the notification of off-site authorities. Specifically, the licensee issued flood warnings to the highway departments of surrounding counties. The flood warnings were in accordance with plant procedures following large discharges from the Lake Anna Dam due to heavy rains. The inspectors reviewed these notifications and verified that there were no NRC safety-related concerns associated with the events.

2) On February 28, 1994, the licensee notified the NRC as required by 10 CFR 50.72 concerning the notification of off-site authorities. Specifically, the licensee notified the Commonwealth of Virginia Department of Environmental Quality concerning a raw sewage release to the site settling pond. The inspectors reviewed this notification and verified that there were no NRC safety-related concerns associated with the event.

3) On March 9, 1994, the licensee notified the NRC as required by 10 CFR 50.72 concerning a loss of emergency off-site response capability. At 7:06 p.m., 22 of the plant's 53 emergency sirens were found to be inoperable. The sirens lost normal power due to a large area power outage caused by a failed substation transformer, and after several hours, the backup batteries became fully discharged. The Commonwealth of Virginia and surrounding counties were notified that other means would be needed for alerting affected area residents in an emergency. By 7:58 a.m. on

March 10, sufficient sirens were returned to service such that emergency response capabilities were considered to be restored.

Additionally, the inspectors reviewed the licensee's methods for determining the operability for early warning sirens. The inspectors identified that the licensee had systems and procedures in place for monitoring the sirens continuously. Additionally, the licensee used procedures for siren polling and testing when monitoring systems indicated potential problems. The inspectors concluded that the licensee's actions for monitoring siren status and procedures for dealing with inoperable sirens were appropriate.

No violations or deviations were identified.

4. Maintenance Observations (62703)

Maintenance activities were observed and reviewed to verify that activities were conducted in accordance with TS, procedures, regulatory guides, and industry codes or standards.

On March 9, 1994, the licensee commenced work to correct problems with water leakage into the lube oil system for the Unit 2 turbine driven auxiliary feedwater pump, 2-FW-P-2. This ongoing problem had been previously reviewed by inspectors and discussed in NRC Inspection Report Nos. 50-338, 339/94-02. The licensee's efforts in this inspection period centered around maintenance to correct problems with steam leakage in the seal housing area which was postulated to contaminate the lube oil by entering the adjacent bearing housing. The licensee reworked the seal housing and reassembled the pump. However, on March 10, post-maintenance testing revealed that the repairs had been unsuccessful and that water content was actually higher than before repairs.

The licensee chose to continue the maintenance in an attempt to stop the leakage through complete seal housing replacement. However, this work was projected to require time exceeding the 72 hours allowed by TS action 3.7.1.2.a. The licensee's staff developed JCO 94-03 for completing the proposed maintenance, and submitted it for SNSOC review. The SNSOC concluded that exceeding the 72 hour action would not have significant adverse safety consequences provided compensatory actions contained in the JCO were followed. Based on this conclusion, the SNSOC approved requesting enforcement discretion from the NRC in order to allow an additional 24 hours to complete the maintenance.

By a telephone conference on March 11, 1994, at 11:00 a.m., the licensee requested that the NRC allow 24 hours for additional maintenance in addition to the 72 hours allowed by TS 3.7.1.2. The licensee provided the request in writing to the NRC later the same day. As compensatory actions, the licensee indicated that no planned maintenance would be performed on the motor driven AFW pumps; no planned maintenance would be performed in the switchyard; no planned maintenance would be performed on the emergency diesel generators; all main feedwater pumps were available with no maintenance planned during the time period; all condensate pumps were available with no maintenance planned during the time period; and operating shifts would be briefed on the actions of abnormal procedure AP-22.1, Loss of 2-FW-P-2 Turbine Driven Aux. Feedwater Pump, specifically the ability to cross-tie AFW pumps if required. Additionally, the licensee demonstrated the safety significance to be small by calculating only a negligible increase in the core damage frequency from internal events. The NRC approved the licensee's request and agreed not to enforce compliance with TS 3.7.1.2 for the period from 5:03 a.m. on March 12, 1994, to 5:03 a.m. on March 13, 1994. The inspectors verified that the licensee complied with the conditions for the enforcement discretion and commitments for compensatory actions. At 8:52 a.m. on March 12, the pump was returned to operable status. The inspectors reviewed the events leading to the request for enforcement discretion and concluded that no regulatory requirements were violated. This enforcement discretion item is considered closed.

Later on March 11, the seal housing replacement was completed. However, post-maintenance testing revealed that the steam leakage continued. Also, significant water amounts were again found to be present in the oil. To reduce the water intrusion, the licensee installed a temporary modification to divert the steam flow away from the bearing. However, testing continued to indicate water intrusion into the lube oil at about a 0.5%/hour rate. After including an allowance for initial water content, this led the licensee to estimate that about a 5% water content would be present in the lube oil after pump design basis operation for eight hours.

During the repair efforts, the licensee was also researching technical information to accurately define the effects of higher water content in the oil upon pump operation. An analysis was performed for a worst case situation encountered during the testing on March 10. During that testing, a 0.74%/hour intrusion rate was observed. The licensee's analysis for this situation concluded that a water content as high as 7.4% could be tolerated without preventing the pump from performing its design safety function. Using these new figures, JCO 94-04 was written and approved by the SNSOC for returning the pump to operation.

The inspectors reviewed JCO 94-04. The JCO addressed both the possible pump effects due to water and oil separation and from a reduction in oil viscosity due to entrained water. The licensee's evaluation that separation would not affect pump operability appeared to be well founded. However, the JCO's conclusions concerning viscosity reduction effects were founded primarily upon written opinions supplied by lubrication engineers and the pump vendor. The opinions were clearly stated as opinions based solely on experience. The inspectors reviewed the supporting documents and concluded that although the JCO appeared to have sufficiently demonstrated that the pump was operable, the JCO's conclusions rested solely upon opinions which had not been validated through formal testing or calculations.

At the inspection period's end, the licensee was planning additional efforts to correct the continuing problem with water intrusion into the lube oil.

No violations or deviations were identified.

5. Surveillance Observations (61726)

Surveillance testing activities were observed and reviewed to verify that testing was performed in accordance with procedures, test instrumentation was calibrated, LCOs were met, and any deficiencies identified were properly reviewed and resolved.

a. Loop Stop Valve Interlock Test

During the previous inspection period, the inspectors reviewed and closed LER 50-338, 339/93-08. An LER portion stated that Unit 2 functional testing would be performed to test the RCS loop stop valve position limit switch inputs to the SSPS during the next scheduled refueling outage in September 1993 and thereafter. The inspectors reviewed 2-MOP-5.91, Returning One or More Reactor Coolant Loops to Service Following Maintenance, revision 9-P2-OT01, performed October 17, 1993, which was credited as meeting this commitment. The inspectors concluded during the previous inspection period that the test met the licensee's commitment for LER closeout. However, during that review, the inspectors raised questions concerning actions taken during test performance which were discussed with the licensee during this inspection period.

The inspectors noted that the verification step which checked the limit switch interlock for the A loop could not be performed at the time due to an equipment failure. Specifically, the step not performed was to verify that the SG level trip, AFW auto start, and differential pressure steam line SI signals were blocked by verifying that annunciator 2P-A5, "RC LOOP 1A STOP VLVS CLSD PERM CHNL I", was lit when the valves were shut. A subsequent step, which was also not performed, verified that the annunciator extinguished and that the protective trips and blocks were removed when the valves were open.

The inspectors reviewed DR 93-1662 which recorded the inability to perform these steps. The DR was resolved by performing an electrical check to ensure that the SSPS interlock for the A loop stop valve was not blocking the actuation logic. This electrical check was described in an engineering memorandum attached to the DR for its resolution. This engineering memorandum was used to record completing an alternate method to check block removal.

After this check was completed, the test was closed. The DR resolution which included this engineering memorandum was later approved by the SNSOC.

However, the inspectors noted that the engineering memorandum did not address the associated annunciator. The inspectors considered this to be inconsistent with the licensee's TS surveillance review finding which was the basis for preforming the test. The TS review finding stated, "Since this interlock can defeat trip or ESF actuations in the event of its failure, it is imperative to verify its proper functioning and annunciation." The inspectors concluded that although operability was established, the test results were inconsistent with the TS surveillance review finding which originally prompted the test.

In addition, the inspectors questioned MOP usage rather than a periodic test procedure for this application. The MOP was a SNSOC-approved procedure, however, steps in the procedure were not performed and SNSOC did not approve the means used to resolve the failure to perform the steps prior to test closeout. The inspectors reviewed the administrative requirements and found that for a MOP, this practice was not prohibited as long as the procedure intent was not changed. The inspectors agreed with the licensee that the procedure's intent to verify clearing the block to signal was not changed. Also, the inspectors noted that the test was not a specific TS requirement and was being conservatively performed by the licensee. The inspectors concluded that the MOP and DR resolution adequately demonstrated that safety functions would not be blocked and that the procedure's intent was met.

b. Safeguards Area Ventilation System Testing

On February 27, 1994, while performing 1-PT-77.1A, Safeguards Area Ventilation System Flow Test - Train A Filter, revision 15-P2, operators did not observe the expected flow changes when securing and starting Unit 2 SAVS fans. The SAVS for each unit had two fans (2-HV-F-40A and B) drawing suction from the safeguards room and discharging into a common plant discharge header to vent stack B. The PT required observing a vent stack recorder trace to verify receiving a 6000 SCFM step increase in flow for each fan. However, operators observed only about a 2500 SCFM change when securing fan B and starting fan A.

The inspectors observed the licensee's response and investigation into the apparently low flow. A system engineer and operators walked down the SAVS and did not find any mispositioned dampers or flow blockage. Also, a flow check at the fan discharge indicated flow greater than that required by TS. After the walkdown and the flow check, the SNSOC was convened and concluded that the SAVS met TS requirements and was operable. On February 28, the licensee performed further testing. The licensee concluded that the low flow indication was most likely due to some discharge flow being diverted from the common header supplying the vent stack. Further investigations identified that a partially open damper in the decontamination building exhaust allowed flow to backflow to that building from the vent stack supply header downstream from the SAVS exhaust. This backflow was evaluated by the licensee and determined not to be a problem. The inspectors concluded that the licensee promptly and thoroughly investigated the low flow condition and properly verified that the flow met TS requirements prior to making a decision concerning SAVS operability.

However, during the inspector's reviews and walkdown, a question developed concerning SAVS design. The inspectors postulated that a single active failure of a supply or return damper from SAVS to the charcoal filter banks on a CDA or the passive failure of a common exhaust duct fire damper could block the system. The inspectors noted that the TS and UFSAR bases for SAVS was to ensure that radioactive materials leaking from the ECCS equipment within the pump rooms following a LOCA were filtered prior to reaching the environment. No clear requirement for SAVS operations to support equipment qualifications in the safeguards room was found. The inspectors requested calculations showing safeguards room area temperatures during design basis conditions and assuming a failure of the SAVS.

The inspectors were provided and reviewed a final type 1 report NES-NP-2422F, Safety Related Pump Room Ventilation North Anna Power Station. The report was written to address concerns raised by the NRC during the 1991 EDSFI. The report did not consider a single failure of one damper rendering both SAVS inoperable, but did calculate each pump cubical temperature for a complete loss of SAVS. All four pump cubicals in the safeguards room were projected to exceed 170°F with the worst reaching 190°F. The inspectors questioned the pumps' qualifications to operate at these elevated temperatures which were above the area's temperature rating. A review by the licensee indicated that the pumps would remain operable for the duration required by the design basis during an accident. At the inspection period's end, the licensee was also reviewing the radiological consequences for the postulated single failure. The licensee initiated DR 94-334 to document that the type 1 study did not consider a single failure that could affect both SAVS. Based on the information supplied by the licensee, the inspectors concluded that safety system operability was not impacted. The inspectors will review the final DR resolution. This is identified as
IFI 50-338, 339/94-05-01: Review DR Resolution Of SAVS Single Failures.

c. Fire Protection System Testing

On March 7, 1994, the inspectors identified that the licensee began a review for surveillances performed on the facility fire protection systems. The review was initiated as an extension to the TS surveillance review completed in June 1993. The fire protection surveillance review involved taking the existing PTs for testing fire protection systems and comparing them to the requirements in the UFSAR chapter 16.

The inspectors learned about the review when DR 94-278 documented inadequate test requirements for the high pressure CO_2 system protecting the FOPH. Specifically, the licensee had identified that no manual actuation test was performed as required by UFSAR surveillance requirement 16.2.1.2.3.3. Also, it was identified that the automatic test did not verify that all valves in the flow path actuated. Once identified, a continuous fire watch was established at the FOPH.

System engineering performed a one time only PAR to 1-PT-104.2.1, Fire Protection - Flow Test High Pressure CO_2 System, revision 3, to functionally test the system via manual actuation. The test was performed on the same day, and the results were unsuccessful. Specifically, the CO_2 system did not actuate and dump into the FOPH room B. The licensee suspected a failed pilot valve or blockage in the line to an air actuated valve, 1-FP-1229. Problems were also noted with equipment for the FOPH room A, but the system did actuate and the test medium discharged into the room. To investigate the failure, on March 9, the licensee obtained vendor assistance and retested the system. This time the system actuated as expected with one problem. During manual actuation testing for the FOPH room A, all CO_2 bottles discharged when only one half were expected to discharge. A failed check valve was suspected and a WR was initiated.

Engineering reviewed the two test results and discussed the system operation with vendor representatives. Engineering recommended that the system be returned to an operable status based on the following: 1) testing demonstrated that the system would perform properly either by manual or automatic actuation, 2) The check valve's failure would not prevent the system from discharging into either FOPH room and, 3) leakage from the system identified during testing was not excessive. On March 9, SNSOC approved the operability determination and the system was returned to an operable status. The inspectors concluded that the system was adequately tested prior to returning it to service.

On March 17, during the review for another test, the licensee informed the inspectors that the control room halon systems were being declared inoperable due to inadequate testing. A continuous fire watch was established. At the inspection period's end, the licensee was still planning corrective actions.

The licensee informed the inspectors that a special report in accordance with UFSAR general requirement 16.2.0.9 would be submitted to the NRC documenting the above failures. The report would include describing the licensee's initiative to review all fire protection surveillance requirements in the UFSAR. The inspectors concluded that the licensee was taking a strong safety initiative to review this area. The inspectors will continue to follow the licensee's efforts during the fire protection surveillance review under IFI 50-338, 339/94-05-02: Evaluate Fire Protection Surveillance Review Results.

No violations or deviations were identified.

6. Licensee Event Report Followup (92700)

The following LERs were reviewed and closed. The inspectors verified that reporting requirements had been met, causes had been identified, corrective actions appeared appropriate, and generic applicability had been considered.

a. (Closed) LER 50-339/93-01: Inoperable Power Range Nuclear Instrument Due To Personnel Error

This LER reported a failure to meet TS 3.3.1.1, Table 3.3-1, action requirements because nuclear instrument channel N42 was inoperable for greater than one hour without being placed in trip. The event occurred because technicians performing an instrument channel check procedure incorrectly reversed detector leads when returning the instrument to service. The problem was not identified until later during evolutions to return another channel to service following a similar test. The licensee concluded the event was caused by human error and inadequate independent verification. This event was also reviewed in NRC Inspection Report Nos. 50-338, 339/93-14, and Violation 50-338/93-14-03 was issued (paragraph 7.b). Immediate corrective actions included placing the channel in trip, reversing the leads, and performing a calibration test to return the channel to service. Additionally, the licensee coached the involved individuals and reviewed the event with all other technicians responsible for similar maintenance in informal and formal training sessions. The inspectors verified that this training was completed and concluded that these actions, when combined with those taken for the associated violation, were adequate.

b. (Closed) LER 50-339/93-06: Steam Generator Tube Defects

This LER reported a C-3 classification in accordance with TS 4.4.5.2 for all three Unit 2 SGs due to SG tube degradation. The licensee's continuing SG tube degradation problems have resulted in Unit 1 SG replacement in spring 1993 and plans for Unit 2 SG replacement in fall 1996. The licensee removed from service all tubes with pluggable indications. Additionally, engineering evaluations were performed which demonstrated that the unit could be operated safely during the current cycle. The inspectors concluded that the licensee's actions were appropriate.

c. (Closed) LER 50-339/93-07: High Head Safety Injection Flow Below Technical Specification Minimum

This LER reported a failure to meet TS 4.5.2.h requirements for HHSI flow identified by the licensee during Unit 2 fall 1993 outage surveillance testing. Upon discovery, immediate corrective actions were taken to restore flows to meet TS requirements, and steps were taken to preclude changes in flows from possible throttle valve movements. Later with Unit 2 at power, investigation results demonstrated that due to measurement uncertainties, flow could no longer be assured to meet the TS requirements. The licensee requested and received an emergency TS change and took compensatory actions to restore the system to meet TS requirements. The inspector's reviews for these actions were discussed in NRC Inspection Report Nos. 50-338, 339/93-27. Long term corrective actions for the event were to be decided following formal root cause evaluation completion.

This event was also discussed in NRC Inspection Report Nos. 50-338, 339/93-28, which proposed violation 50-339/93-28-01 for the failure to meet TS 4.5.2.h requirements. This violation was the subject of escalated enforcement action, EA-93-262, and issuance of a civil penalty. In response to violation 50-339/93-28-01, the licensee committed to inform the inspectors concerning the long term corrective actions resulting from the root cause evaluation. The inspectors will evaluate these long term corrective actions when reviewing violation 50-339/93-28-01 for closure. The inspectors concluded that the licensee's actions to date were adequate for LER closure.

d. (Closed) LER 50-338/93-14: Steam Driven Auxiliary Feedwater Pump Inoperable Due To An Incorrect Speed Control Setting Following Annual Preventive Maintenance

This LER reported the licensee's identification that the speed setting for the Unit 1 turbine driven auxiliary feed water pump was not reset following overspeed trip testing. This resulted in the pump being inoperable for approximately four days. The cause for the error was concluded to be maintenance personnel's failure to follow procedure during the overspeed trip testing. The licensee's corrective actions included resetting the speed setting, coaching maintenance personnel on following procedures, and enhancing preventive maintenance procedure 0-MPM-0102-01, Auxiliary Feed Pump Preventive Maintenance. The inspectors concluded that these actions were adequate and verified that they were completed. This event was also reviewed in NRC Inspection Report Nos. 50-338, 339/93-14, and Violation 50-338/93-14-02 was issued (paragraph 7.a).

No violations or deviations were identified.

7. Action on Previous Inspection Items (92702)

The following previous inspection items were reviewed and closed:

a. (Closed) VIO 50-338/93-14-02: Mode Change With Inoperable AFW Pump

This violation was issued for the licensee's failure to meet TS requirements for turbine driven AFW pump operability due to an incorrect speed setting. The licensee's corrective actions for the violation were the same as those for the related LER, 50-338/93-14 (paragraph 6.d). The inspectors concluded that the licensee's response, dated July 2, 1993, to the violation and the corrective actions were adequate.

b. (Closed) VIO 50-339/93-14-03: Failure to Follow Procedure During Power Range Channel Checks

This violation was issued for the licensee's failure to properly follow the procedure for an N42 channel calibration test which resulted in reversing the two detector inputs to the channel. The licensee's corrective actions for the violation included those for the related LER, 50-339/93-01 (paragraph 6.a). In addition to the corrective actions discussed in the LER, the licensee performed a study on the effects for the reversed inputs. The study concluded that although the channel was inoperable, the channel remained capable of generating reactor trip inputs assumed in accident analysis. Also, the licensee issued a memorandum to licensed operators reminding them to be attentive to control room indications when returning instrumentation to service following maintenance. The inspectors concluded that the licensee's response, dated July 2, 1993, to the violation and the corrective actions were adequate.

No violations or deviations were identified.

8. Exit Interview

The results were summarized on March 25 and April 7, 1994, with those persons identified in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results addressed in the Summary section and those listed below.

Type	Item Number	Status	Description
IFI	50-338, 339/94-05-01	Open	Review DR Resolution Of SAVS Single Failures (paragraph 5.b)
IFI	50-338, 339/94-05-02	Open	Evaluate Fire Protection Surveillance Review Results (paragraph 5.c)

Type	Item Number	Status	Description
LER	50-339/93-01	Closed	Inoperable Power Range Nuclear Instrument Due To Personnel Error (paragraph 6.a)
LER	50-339/93-06	Closed	Steam Generator Tube Defects (paragraph 6.b)
LER	50-339/93-07	Closed	High Head Safety Injection Flow Below Technical Specification Minimum (paragraph 6.c)
LER	50-338/93-14	Closed	Steam Driven Auxiliary Feedwater Pump Inoperable Due To An Incorrect Speed Control Setting Following Annual Preventative Maintenance (paragraph 6.d)
VIO	50-338/93-14-02	Closed	Mode Change With Inoperable AFW Pump (paragraph 7.a)
VIO	50-339/93-14-03	Closed	Failure to Follow Procedure During Power Range Channel Checks (paragraph 7.b)

Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

9. Index of Acronyms and Initialisms

AFW	AUXILIARY FEEDWATER
CC	COMPONENT COOLING
CDA	CONTAINMENT DEPRESSURIZATION ACTUATION
CFR	CODE OF FEDERAL REGULATIONS
DBD	DESIGN BASIS DOCUMENT
DR	DEVIATION REPORT
ECCS	EMERGENCY CORE COOLING SYSTEM
EDSFI	ELECTRICAL DISTRIBUTION SYSTEM FUNCTIONAL INSPECTION
ESF	ENGINEERED SAFETY FEATURE
EWR	ENGINEERING WORK REQUEST
F	FAHRENHEIT
FOPH	FUEL OIL PUMP HOUSE
HHSI	HIGH HEAD SAFETY INJECTION
HPES	HUMAN PERFORMANCE EVALUATION SYSTEM
IFI	INSPECTOR FOLLOW-UP ITEM
JCO	JUSTIFICATION FOR CONTINUED OPERATION
LCO	LIMITING CONDITION FOR OPERATION
LAN	LOCAL AREA NETWORK
LER	LICENSEE EVENT REPORT

LOCA	LOSS OF COOLANT ACCIDENT
MOP	MAINTENANCE OPERATIONS PROCEDURE
NRC	NUCLEAR REGULATORY COMMISSION
PAR	PROCEDURE ACTION REQUEST
PT	PERIODIC TEST
RCS	REACTOR COOLANT SYSTEM
SAVS	SAFEGUARDS AREA VENTILATION SYSTEM
SCFM	STANDARD CUBIC FEET PER MINUTE
SG	STEAM GENERATOR
SI	SAFETY INJECTION
SNSOC	STATION NUCLEAR SAFETY AND OPERATING COMMITTEE
SSPS	SOLID-STATE PROTECTION SYSTEM
SW	SERVICE WATER
TS	TECHNICAL SPECIFICATIONS
UFSAR	UPDATED FINAL SAFETY ANALYSIS REPORT
VIO	VIOLATION
WR	WORK REQUEST