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

Report Nos.: 50-327/92-02 and 50-328/92-02

Licensee: Tennessee Valley Authority
6N 38A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

Docket Nos.: 50-327 and 50-328 License Nos.: DPR-77 and DPR-79

Facility Name: Sequoyah Units 1 and 2

Inspection Conducted: January 5 through February 1, 1992

Lead Inspector: Paul Kellogg for
W. E. Holland, Senior Resident Inspector — Date Signed: 2/18/92

Inspectors: S. M. Shaeffer, Resident Inspector
R. D. McWhorter, Resident Inspector

Approved by: Paul Kellogg
Paul J. Kellogg, Chief, Section 4A
Division of Reactor Projects — Date Signed: 2/18/92

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant operations, plant maintenance, plant surveillance, evaluation of licensee self-assessment capability, licensee event report closeout, followup on previous inspection findings, and engineered safety features system walkdown. During the performance of this inspection, the resident inspectors conducted several reviews of the licensee's backshift or weekend operations.

Also, a special announced inspection discussed in paragraph 10 evaluated the capability of the licensee to conduct safety assessments and safety evaluation of activities conducted at the Sequoyah Nuclear Plant, Units 1 and 2, related to the requirements of 10 CFR 50.59, "Changes, Tests, and Experiments." The inspection included an evaluation of the capability of the program as implemented in various procedures and controls, an evaluation of the effectiveness of the program to train and qualify personnel to perform safety assessments and safety evaluations, and an evaluation of the program effectiveness as evidenced by examination of various completed safety

assessments and evaluations. The following NRC personnel were involved in this inspection:

Lead Inspector: D. E. LaBarge, Senior Project Manager, NRR
Inspectors: D. H. Moran, NRR Project Engineer
W. E. Holland, Senior Resident Inspector, RII
H. O. Christensen, Region II Section Chief

Results:

In the Operations functional area, a violation was identified for failure to follow drawing control procedures resulting in uncontrolled and improperly maintained plant drawings being available for operator use in the plant (paragraph 3.a).

In the Operations functional area, a non-cited violation was identified for failure to follow the requirements of SOI-78.1 with regard to failure to maintain a valve in a locked configuration (paragraph 3.b).

In the Operations functional area, a non-cited violation was identified for failure to comply with the requirements of 10 CFR 55.53(e) and procedure AI-30, with regard to a licensed operator being on shift in a licensed position without satisfying watch-standing requirements for the previous quarter (paragraph 3.c).

In the Maintenance/Surveillance functional area, both a strength and a weakness were identified during a maintenance activity to replace the Unit 1 letdown line relief valve. The strength was identified with regard to ALARA, work performance, and personnal safety measures. The weakness was identified with regard to assuring that operators fully understood the latest management plan for execution of the job, specifically Technical Specification entry and exit (paragraph 4.a).

In the Operations functional area, a weakness was identified in attention to detail in control of system configuration outside of main safety flowpaths. Also, a problem was identified with regard to a lack of adequate attention being focused on the plant component identification tag program (paragraph 9).

In the Safety Assessment/Quality Verification functional area, a review of the licensee's safety assessment/safety evaluation program shows evidence of extensive prior planning and implementation of detailed procedures, well trained and qualified personnel, and comprehensive evaluations, which adequately implement the requirements of 10 CFR 50.59. However, several minor problems were noted during the review of program implementation which were attributed to a lack of "attention to detail" (paragraph 10).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

#*J. Wilson, Site Vice President
#R. Alsup, QA Audit Manager
#*R. Beecken, Plant Manager
#L. Bryant, Maintenance Manager
#S. Childers, Operations
#W. Cobean, Advisor to TVA Board
#*M. Cooper, Site Licensing Manager
#M. Cutlip, Corporate Site Coordinator
*T. Flippo, QA Manager
J. Gates, Technical Support Manager
*M. Hellums, Project Engineer
T. Holloman, Technical/Engineering Support
W. Justice, Safety Analysis Engineer
#C. Kent, Radiological Control Manager
#W. Lagergren, Jr., Operations Manager
#M. Lorek, Operations Superintendent
*R. Lumpkin, Site Quality Manager
#P. Lydon, Operations Manager (as of 2-3-92)
R. Martin, Controller
#J. Miller, Maintenance Electrical Supervisor
L. Mynatt, Training Department
*J. Proffitt, Compliance Licensing Engineer
*R. Rausch, Modification Manager
#R. Rogers, Technical Support Manager
*T. Rutledge, Technical Support Engineer
*J. Smith, Regulatory Licensing Manager
*S. Taylor, Engineering Training Specialist
#*R. Thompson, Compliance Licensing Manager
P. Trudel, Nuclear Engineering Manager
#C. Wittemore, Licensing Engineer

NRC Employees

*F. Hebdon, NRR Project Director
*B. Wilson, Chief, DRP Branch 4
P. Kellogg Chief, DRP Section 4A

*Attended 50.59 exit interview on January 17, 1992.

#Attended resident exit interview on February 5, 1992.

Other licensee employees contacted included control room operators, shift technical advisors, shift supervisors and other plant personnel.

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

On January 6, 1992 the NRC Region II Section Chief, Paul J. Kellogg visited the Sequoyah Nuclear Plant. Mr. Kellogg attended the previous month's resident inspection exit meeting, toured the plant with the inspectors, and discussed current issues at the facility.

On January 16, 1992 NRC management visited the Sequoyah Nuclear Plant. The NRC Managers were:

L. Reyes, Director, Division of Reactor Projects, RII
F. Hebdon, NRR Project Director
B. Wilson, Chief, Branch 4, Division of Reactor Projects, RII

The managers toured the plant with the resident inspectors and discussed items of mutual interest with licensee plant and QA management. On January 17, 1992, the managers listed above, with the exception of Mr. Reyes, held additional discussions with licensee management and attended the exit for the 10 CFR 50.59 safety evaluation program inspection.

2. Plant Status

Unit 1 operated at approximately full power throughout the inspection period.

Unit 2 began the inspection period at full power. The unit operated at approximately full power until January 28, when the unit commenced coastdown operations which will continue up to the Unit 2, Cycle 5 refueling outage scheduled to start in March 1992. At the end of the period, the unit was operating at approximately 95 percent power.

3. Operational Safety Verification (71707)

a. Daily Inspections

The inspectors conducted daily inspections in the following areas: control room staffing, access, and operator behavior; operator adherence to approved procedures, TS, and LCOs; examination of panels containing instrumentation and other reactor protection system elements to determine that required channels are operable; and review of control room operator logs, operating orders, plant deviation reports, tagout logs, temporary modification logs, and tags on components to verify compliance with approved procedures. The inspectors also routinely accompanied plant management on plant tours observed the effectiveness of management's influence on activities being performed by plant personnel.

On January 6, 1992, during a routine walkdown, the inspectors identified several drawing discrepancies which included drawings not properly labeled as controlled drawings and interfiling different

revisions of the same drawing. The drawings were located on the 669 elevation of the auxiliary building inside a plastic, wall mounted drawing holder. The inspectors questioned the licensee with regard to control and maintenance of these drawings, which could be utilized by operations personnel for system reference. Document Control and Records Management (DCRM) personnel update the major control drawing locations such as the control room, TSC, and the 8 and 24 hour technical information centers. The isolated occurrences identified by the inspectors were located in "satellite" drawing stations not filed by DCRM personnel and are maintained by the responsible plant section in accordance with plant procedures. The licensee initially indicated that recent changes in the responsible department for updating the subject drawings lead to several isolated occurrences where the current revisions of the drawings were not appropriately identified and filed as controlled drawings. The inspectors were later informed that the discrepancies had been corrected.

Upon a subsequent review by the inspectors of the same area late in the inspection period, including the AUO station and nearby drawing storage on the 669 elevation of the auxiliary building, other examples of control drawing labeling discrepancies and several outdated drawing revisions were identified. A separate concern was also identified with regard to the practice of storing numerous drawings identified as "As Designed/Over the Counter" in open areas which were accessible to operators for use or reference. "For Information Only" drawings were also posted in the AUO station. The inspectors immediately performed a review of the control room and TSC controlled drawings and did not identify any of the previously noted discrepancies. The inspector informed the licensee of the additional problems. The licensee then requested that the QA organization conduct a survey to identify any further problems in the other areas of the plant. The results of the timely QA survey confirmed the problems that were identified by the inspector, and further identified that similar problems were occurring in other satellite control drawing areas of the plant where DCRM personnel were not responsible for filing. The areas and problems identified by the initial QA audit included:

1) Auxiliary Building elevation 669 - Drawings not properly updated at AUO station.

2) CDWE Building - One stick of uncontrolled drawings and one uncontrolled drawing in a plexiglass holder at the operations work station.

3) Turbine building - Approximately 100 interfiled drawings (dual revisions of same drawing in same location).

4) Auxiliary Building elevation 669 - One uncontrolled drawing was found in a plexiglass holder near the boric acid evaporator.

At the end of the inspection period the licensee was continuing to audit the areas not covered by the initial QA assessment. As a result of the inspectors findings and the QA assessment, PER SQPER920015 was initiated to document the overall problem of uncontrolled and improper updating of drawings at operations work stations. Immediate corrective actions included the removal of the inappropriate and excess drawings and verification that the proper revisions were in place. The licensee was also planning to replace all the drawings in the auxiliary and turbine building areas.

Technical Specification 6.8.1 requires, in part, that written procedures shall be implemented to address administrative control of plant drawings. Site Standard Practice (SSP) 10.1, CONTROLLING DRAWINGS, REVISION 0, details the licensee's administrative controls for drawing updates and maintenance. Section 3.4.D requires, in part, that controlled drawing holders ensure that controlled drawings are received, properly filed, receipt acknowledged, and maintained in a current state. Section 3.7.B additionally requires the DCRM manager to ensure the proper stamp (controlled) is placed in red ink on the drawings. The failure to follow these requirements by not properly filing, maintaining and identifying controlled drawings as determined by both NRC and licensee reviews is identified as a violation of TS 6.8.1 for failure to follow the requirements of SSP-10.1, REVISION 0 (327, 328/92-02-01).

The inspectors also discussed with the licensee the use, posting, and storage of numerous "as designed" and "For-Information Only" drawings in the safety-related areas of the plant. Although this practice appears to be allowed by the licensee's procedures, the inspectors were concerned that permanent storage and posting of such drawings at operation stations allows opportunities for operations personnel to use outdated and uncontrolled drawings for plant activities. Licensee management agreed to review this issue and take appropriate corrective action.

On January 9, 1992, during review of the licensee's plan of the day meeting, the inspectors noted that licensee management was discussing the possibility of gagging one of the Unit 1 pressurizer code safety valves for approximately 3 hours in order to reduce a leakage condition that has been observed during current unit operation. At the time of discussion, Unit 1 was at approximately 98 percent power (MODE 1 operation). The inspectors questioned the licensee with regard to whether TSs allowed for operation with one of the three pressurizer code safety valves inoperable (gagged). The licensee stated that the action statement for the pressurizer code safety valves did provide for the time in question (approximately 3 hours) to allow for inoperability of one safety valve.

After the meeting, the inspectors reviewed TS 3.4.3.1 which requires that all pressurizer code safety valves shall be OPERABLE in MODES 1, 2, and 3. The ACTION statement for TS 3.4.3.1 states "with one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours."

The inspectors conducted an additional review of operator logs for the Unit 1 startup in December 1991 and noted that one of the pressurizer code safety valves had been gagged during operation in MODE 3. This evolution was accomplished on December 13 at 2307 hours and the valve remained inoperable (gagged) until December 14 at approximately 0348 hours. In addition, the log review also identified that the licensee entered the ACTION statement for TS 3.6.5.5 at 1216 hours on December 13 (opening of pressurizer access enclosure) in order to gain access to the pressurizer code safety valve. This Action statement was exited on December 14 at 0445 hours.

The inspectors reviewed TS 3.6.5.5 which requires that the personnel access doors and equipment hatches between the containment's upper and lower compartments shall be OPERABLE and closed in MODES 1, 2, 3, and 4. TS 3.6.5.5 ACTION statement states "with a personnel access door or equipment hatch inoperable or open except for personnel transit entry, restore the door or hatch to OPERABLE status or to its closed position (as applicable) within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours."

The inspectors' review of the TS requirements and ACTION statements resulted in a determination that any action which would make one of the pressurizer code safety valves inoperable (i.e. "gagging") may not be allowed by the TS. They also considered that the licensee action with regard to opening of the pressurizer access enclosure may not be allowed by the TS. NRC, Region II has submitted a formal request to NRC, NRR to resolve this potentially generic TS interpretation issue. During the interim, the NRC has verbally informed the licensee that it is their responsibility to assure that TS AOT and SDT ACTION statements be used in a manner which assures that the plants are operated safely and proper considerations be given when using SDT from ACTION statements to conduct maintenance activities.

b. Weekly Inspections

The inspectors conducted weekly inspections in the following areas: operability verification of selected ESF systems by valve alignment, breaker positions, condition of equipment or component, and

operability of instrumentation and support items essential to system actuation or performance. Plant tours were conducted which included observation of general plant/equipment conditions, fire protection and preventative measures, control of activities in progress, plant housekeeping conditions/cleanliness, radiation protection controls, and missile hazards.

On January 9, 1992, the inspectors identified that a normally closed and locked primary water valve was left unattended and unlocked on the 690 elevation of the auxiliary building. The valve, 0-78-522, is the primary water makeup isolation to the spent fuel pit. The valve appeared to be in the required closed position and was also tagged with WR 078380 dated August 30, 1991, which stated that the valve had a broken stem. The locking device and chain were hanging off the valve at the time of discovery. The inspector informed the control room of the issue, and an operator was dispatched to review the valve alignment. The operator verified the valve was in the required closed position and relocked the valve. The operator noted that the valve stem was operable and not broken as indicated on the WR. However, the Grinnel valve position indicator stem was broken and not operable. The operator then verified correct positions and locking devices of numerous other valves in the associated system. No other discrepancies were identified.

The licensee initiated PER SQPER 920009 due to the inspectors identification of the unlocked valve. The licensee's investigation revealed that the valve was most likely last manipulated on September 15, 1991 after the broken indicator stem was identified in August of 1991. After this manipulation, the valve was independently verified as being left closed and locked per System Operating Instruction (SOI) 78.1, SPENT FUEL PIT COOLANT SYSTEM, REVISION 39. This SOI utilizes the valve to provide primary water makeup to the spent fuel pit when desired. Outside of this use, the valve is also required by SOI-78.1 to be verified in the closed position during outage evolutions such as dewatering the refueling canal and refueling canal purification. Interviews with personnel involved with the outage activities could not establish if the valves were unlocked during the Unit 1 outage activities. The inspector discussed this event with operations management and concluded that the valve was apparently unlocked for an undetermined reason after September 15, 1991 and left unlocked contrary to the configuration control requirement in SOI-78.1. The inspectors also concluded this problem to be an isolated occurrence. The failure to maintain 0-78-522 in a locked configuration per SOI-78.1, is identified as a non-cited violation of TS 6.8.1 (327, 328/92-02-02). The violation is not being cited because the criteria specified in Section V.A. of the Enforcement Policy were satisfied.

c. Biweekly Inspections

The inspectors conducted biweekly inspections in the following areas: verification review and walkdown of safety-related tagouts in effect; review of the sampling program (e.g., primary and secondary coolant samples, boric acid tank samples, plant liquid and gaseous samples); observation of control room shift turnover; review of implementation and use of the plant corrective action program; verification of selected portions of containment isolation lineups; and verification that notices to workers are posted as required by 10 CFR Part 19.

On January 1, 1992, a problem occurred where a licensed SRO stood one eight hour shift as Unit 1 ASOS without properly meeting the requirements for maintaining an active operator license. 10 CFR 55.53(e) and facility procedure AI-30, NUCLEAR PLANT CONDUCT OF OPERATION, REVISION 36, require that a licensed individual stand seven eight-hour shifts per quarter to maintain an active license status. Contrary to these requirements, the individual stood only four eight-hour shifts in the previous quarter. The licensee discovered the problem as a part of a routine review, initiated a Problem Evaluation Report (SQPER920007), and informed the NRC Resident Inspectors of the incident on January 10, 1992. The licensee indicated that the individual involved had mistakenly counted shifts stood in September as a part of the October-December quarter. Also, contrary to the requirements of AI-30, the SOS did not have a correct list of active licenses available. The licensee has taken action to review the incident with all operations personnel and has changed the processing of the current listing of licensed operators. This change is to ensure that the SOS receives a monthly update, and that operations management reviews the list on a monthly basis as well. This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section V.G of the Enforcement Policy. This item is identified as an NCV (327, 328/92-02-03).

d. Other Inspection Activities

Inspection areas included the turbine building; diesel generator building; ERCW pumphouse; protected area yard; control room; vital 6.9 kv shutdown board rooms, 480 V breaker and battery rooms; auxiliary building areas including all accessible safety-related pump and heat exchanger rooms. RCS leak rates were reviewed to ensure that detected or suspected leakage from the system was recorded, investigated, and evaluated; and that appropriate actions were taken, if required. RWPs were reviewed, and specific work activities were monitored to assure they were being accomplished per the RWPs. Selected radiation protection instruments were periodically checked, and equipment operability and calibration frequencies were verified.

On January 6, during a routine tour of the safety-related pump rooms, the inspectors noted that the radiological survey map posted outside of the 1B-B RHR pump room did not accurately reflect actual room conditions. The survey map, which had been updated on January 3, indicated that the contaminated area zone boundary was located at the end of the access corridor approximately 6 feet from the pump; however, the actual boundary was established at the entrance to the pump room. Aside from the inaccurate posting, the contamination zone boundary was properly established. The inspectors informed radiological control management of the posting discrepancy and it was promptly corrected. The inspector was informed that the boundary had been moved to the entrance after the initial posting of January 3 and should have been updated to reflect the change. No further problems were noted.

On January 23, the inspectors observed the receipt and handling of new fuel from shipping containers into dry storage locations. The control and execution of the evolution appeared good, with no deficiencies noted.

On January 24, the licensee's radiological control group stated that improved access to the safety-related high head charging pump rooms has been achieved due to ongoing recovery efforts. The reduction in contaminated areas around the pumps allows for plant operators to conduct routine tours in these areas without having to wear protective clothing in these safety-related pump rooms.

e. Physical Security Program Inspections

In the course of the monthly activities, the inspectors included a review of the licensee's physical security program. The performance of various shifts of the security force was observed in the conduct of daily activities to include: protected and vital area access controls; searching of personnel and packages; escorting of visitors; badge issuance and retrieval; and patrols and compensatory posts. In addition, the inspectors observed protected area lighting, and protected and vital areas barrier integrity.

f. Licensee NRC Notifications

(1) On January 18, 1992 the licensee made a call to the NRC as required by 10 CFR 50.72 regarding a spurious radiation monitor spike which resulted in a Unit 1, Train B Containment Ventilation Isolation (CVI) Signal. The CVI system functioned as designed. After determination that the signal was spurious, the operators realigned the ventilation dampers to their normal position and processed a work request to investigate the problem. The monitor involved, 1-RM-90-131, had the high radiation relays removed for troubleshooting activities. By the end of the reporting period, the licensee had not identified any specific cause for the spurious actuation and will continue to

investigate further before placing the monitor back in service. Radiation monitor 1-RM-90-130 remained operable throughout the event. The licensee is conducting an incident investigation on the event and is planning to submit an LER.

Within the areas inspected, one violation and two non-cited violations were identified.

4. Maintenance Inspections (62703 & 42700)

During the reporting period, the inspectors reviewed maintenance activities to assure compliance with the appropriate procedures and requirements. Inspection areas included the following:

a. On January 21, valve 1-62-662, Unit 1 Letdown Line Relief Valve, was replaced while the unit was in mode 1. Control Room direction and coordination of maintenance inside containment was observed by NRC inspectors. The inspectors found that the actual performance of the work was well executed and ensured a difficult task was done quickly and efficiently. As a result of good work practices, radiation exposure for workers was only approximately 15% of the anticipated (planned) dose. Numerous measures were taken to ensure personnel safety throughout planning and during work. Several excellent examples were noted in the licensee's preparation to cope with the hazards which might occur if an RCS safety valve were to discharge to the PRT during the work. However, a weakness in work planning was noted, with an evident breakdown in communications between operations management and personnel working on the job.

Early in the evolution, operators and workers agreed to place the letdown orifice isolation valves in auxiliary mode, rendering them inoperable, in order to provide for shutting a second isolation valve from the RCS for personnel safety. This was not a part of the latest plan of action desired by management. Since these valves are containment isolation valves, entry into TS ACTION 3.6.3.a was made. This ACTION placed a four hour time limit on the evolution. When the four hour limit was approached, operators were preparing to stop work to realign the system and exit the LCO. At that time, the Operations Superintendent intervened and directed that the Letdown Orifice Isolation Valves be restored to normal in order to exit the LCO. He also directed that work proceed with single valve protection for personnel safety, and that the valves be left operable, making further LCO entry unnecessary. Work was then successfully completed with the orifice isolation valves fully operable. The entry into TS 3.6.3.a and the potential to interrupt the work could have been avoided if a current and formally approved plan of action had been available in the control room for operator use.

The main problem was that actions taken by operators in establishing conditions for the work and entering TS LCOs deviated from what was

expected and approved in the final plan by management. Also, the plan in use in the control room was outdated in that it listed LCOs which were not applicable and did not list the actual planned TS entry and exit points. Although no TSs or facility procedures were violated, a portion of the system was rendered inoperable contrary to the intention of the latest plan approved by management. This problem in communications was corrected by management during the work progression without having a major impact on the success of the job.

b. On January 21, the inspectors reviewed maintenance activities related to the replacement of cell 9 of Vital battery II. The cell was previously identified as not meeting pilot cell voltage acceptance criteria as detailed in SI-100.1, VITAL BATTERY WEEKLY INSPECTION, REVISION 17. This SI is performed weekly on the worst case (indicated as the pilot) cells which are identified on a quarterly basis. Cell 9 had been approaching the pilot cell voltage limit of 2.13 and eventually failed the acceptance criteria during the November 11, 1991 performance of the weekly SI. After a failed attempt to allow a high level equalization charge to recover the battery cell, the licensee determined that replacement was necessary. The inspectors observed several evolutions of the replacement work in progress. Overall performance of the work activities was adequate; however, during review of the maintenance documentation, MI-10.53, VITAL BATTERY CELL REPLACEMENT AND/OR BATTERY BANK BUS REWORK SYSTEM 250, REVISION 3, several prerequisite steps were not properly documented as complete even though the battery replacement was already accomplished. The inspectors informed the maintenance personnel of the documentation discrepancy and verified that the prerequisites were actually accomplished which included material staging, measuring and test equipment identification, and personnel safety considerations. After completion of the work activities, the battery was placed on equalization charge until functional testing could be performed. No other problems were noted during the procedure review.

On January 31, the battery successfully passed a performance discharge test utilizing 105.2, VITAL BATTERY BANK II AND 125V BATTERY CHARGER II PERFORMANCE TESTS (SYSTEM 250), REVISION 0. At the end of the assessment period, the battery was on equalization charging, awaiting performance of SI-100, VITAL BATTERY OPERABILITY, REVISION 24, which is the final PMT for the cell replacement. The SI verifies adequate battery parameters including specific gravity, voltage, connection resistance, electrolyte level, and cell temperature. The test establishes the battery's capability of meeting a Design Basis Accident and satisfies several TS surveillance requirements on the D.C. power source. The inspectors will continue to monitor the final operability verifications on the battery during subsequent inspections.

All of the licensee's vital batteries are of a 1974 vintage and are required to be replaced by June of 1994 due to recommended end of life considerations. The licensee has already established plans to replace all five of the vital batteries starting with the fifth (spare) battery after completion of the Unit 2 cycle 5 refueling outage. The inspectors determined that the failure rate of individual cells in the existing vital batteries was not excessive and concluded that adequate monitoring of the worst case cells was being accomplished.

c. During the latter part of the inspection period, the inspectors noted the licensee had identified that a boric acid blockage had occurred in the Unit 1 CVCS flowpath for emergency boration into the suction lines of the charging pumps. The inspectors requested that the licensee provide additional information on this issue. A meeting was held between the inspectors and licensee engineering and operations personnel on January 30, 1992. During that meeting, the inspectors were informed that part of the problem was due to the manner in which heat trace circuitry was installed and controlled on the over 300 feet of piping that was in the flowpath of concern. The inspectors noted that engineering involvement was extensive at this time; however, long term corrective actions to eliminate these type of problems had not been formalized. In addition, the inspectors noted that a continuous annunciation of heat trace trouble for Unit 1 was observed since unit restart from the Unit 1, Cycle 5 outage in the control room. The licensee had also instituted an incident investigation to review the blockage issue. The inspectors will continue to follow the licensee's corrective actions for this problem after the incident investigation is completed.

Within the areas inspected, no violations were identified.

5. Surveillance Inspections (61726 & 42700)

During the reporting period, the inspectors reviewed various surveillance activities to assure compliance with the appropriate procedures and requirements. Inspection areas included the following:

On January 24, the inspectors observed the conduct of 2-SOI-130.1.2, TURBINE DRIVEN AUXILIARY FEEDWATER PUMP 2A-S QUARTERLY OPERABILITY TEST, REVISION 5. Test was properly conducted and performed, with correct documentation of equipment performance. The completed test documentation was also reviewed, and no discrepancies were noted. The only data point which fell out of the "normal range" was recirculation flow rate, which fell into the "alert range". This problem was properly noted, and appropriate action was initiated in periodic test scheduling.

Within the areas inspected, no violations were identified.

6. Evaluation of Licensee Self-Assessment Capability (40500)

During this inspection period, selected reviews were conducted of the licensee's ongoing self-assessment programs in order to evaluate the effectiveness of these programs. The inspectors specifically focused on several of the licensee's incident investigations during the inspection period.

a. Incident Investigation S-91-136, MSIV Jumpers

On January 6, 1991 the inspectors monitored the licensee's PERP meeting which presented the initial findings and recommended corrective actions for the subject II. The subject issue was addressed in detail in NRC Inspection Report 327,328/91-31. The inspectors noted that the review was conducted in a very through manner, that management involvement in the process was appropriate to insure that all identified issues received corrective action attention, and that the root cause of the problem was identified.

b. Incident Investigation S-91-137, Generator CT Problem

On January 15, the inspectors monitored the licensee's PERP meeting which detailed the initial findings and corrective actions for the subject II. The event involved a wiring error during maintenance activities on the current transformers (CT) to the main transformer differential relays. Three of the six CTs, located on the neutral side of the generator, were found to have been installed with their leads rolled which resulted in a main generator trip when Unit 1 was returning to power operation after the cycle 5 refueling outage. The inspectors considered that the licensee's review appropriately detailed the root cause and contributing factors of the event.

The inspector did note numerous similarities of this event to a previous event which involved electrical jumpers being left in place on the A train actuation circuitry of the Unit 1 MSIVs. These similarities included: inadequate PMT in conjunction with second party verification; multiple electrical terminations (up to 40) performed via one signoff; and portions of the WP (drawings) not utilized in the field as required. The inspectors considered the causes of the CT wiring discrepancies as additional examples of problems identified in NRC Inspection Report 327,328/91-31 regarding the licensee's work planning, control and implementation processes.

c. Incident Investigation S-92-003, Missed Surveillance for Electric Board Room Air Handling Unit, Diesel Generator Load Sequence Timer (EB-ST).

On January 30, the inspectors monitored the licensee's PERP meeting which detailed the initial findings and corrective actions for the subject II. The event involved the missing of a surveillance on the subject equipment due to the incorrect deferral of the work request to accomplish required calibrations. The licensee identified as the root cause that procedure, SSP-2.3, ADMINISTRATION OF SITE

PROCEDURES, did not clearly require procedures personnel processing a change to incorporate the relays into an SI to include the Periodic Test Section in the SI revision review chain. Had the Periodic Test Section reviewed the SI revision, the work would have been appropriately tracked as a TS surveillance requirement, rather than a single work request. The licensee identified appropriate corrective actions related to both the root cause and other problems revealed by the investigation. The licensee is preparing an LER on the incident.

One concern raised by the IT was the current status of tracking of hard dates (such as equipment qualification dates, commitment dates, CQAR dates, etc.) for work requests. The recently implemented work control tracking system, MPAC, does not provide a means for entering dates for WR tracking and review which cannot be restricted for change by authorized personnel only. The licensee stated that an audit of all work requests is currently underway to ensure that other hard dates are being properly tracked, and that most safety related dates are also tracked by other systems.

Within the areas inspected, no violations were identified.

7. Licensee Event Report Review (92700)

The inspectors reviewed the LERs listed below to ascertain whether NRC reporting requirements were being met and to evaluate initial adequacy of the corrective actions. The inspector's review also included followup on implementation of corrective action and/or review of licensee documentation that all required corrective action(s) were either complete or identified in the licensee's program for tracking of outstanding actions.

(Closed) LER 327/91-08, Inoperable penetration seals that were not inspected or identified as a result of a deficient procedure. The event, discovered on April 29, 1991, involved the licensee's identification that certain fire barrier penetration seals had not been visually inspected as required by TS 4.7.12. Technical inadequacies in SI-233.1E, MECHANICAL PENETRATION FIRE BARRIER VISUAL INSPECTION, which included inadequate acceptance criteria, were discovered during investigations of previously identified fire barrier discrepancies. The SI inadequacies contributed to not identifying the discrepancies as inoperable penetration seals during a May 1990 performance of TS 4.7.12 surveillance. It was subsequently determined in April of 1991 that the duration of the condition before identification was inappropriately not considered during an initial operability determination. The licensee discovered the error during detailed fire protection reviews being conducted due to ongoing fire protection program problems. The root cause of the discrepancies was an inadequate surveillance. Inaccessibility of the subject penetrations was also identified as a contributing factor. The inspectors verified implementation of corrective actions which included procedure revisions to clarify inspection requirements and correct acceptance criteria,

performance of the required surveillance areas utilizing the revised procedure, and training for the SI performers. One remaining performance utilizing the revised procedure remains to be performed. SI-233.1B is scheduled to be accomplished during the Unit 2 Cycle 5 refueling outage.

(Closed) LER 327/91-13, Inoperable penetration seals that were not inspected or identified as a result of a deficient procedure. The issue involved the discovery of fire barrier penetration seals which were not properly sealed and visually inspected as required by TS 4.7.12. The subject event was identified during corrective actions being conducted due to deficiencies identified in LER/91-08. The corrective actions for the previous event were not complete at the time of discovery of the second event. Due to the similarities in the events, the licensee's corrective actions for LER 91-13 were accomplished under LER 91-08. Based on a review of the corrective actions for the previous event above and a review of Incident Investigation report II-S-91-055, the inspectors concluded that the corrective actions were adequate to address the issue.

(Closed) LER 328/91-03, Power Not Removed From Cold Leg Accumulator Isolation Valve as a Result of Inappropriate Personnel Actions. The subject event was previously evaluated in NRC inspection report 327,328/91-06, and a violation was issued for failure to implement independent verification to ensure the breaker to the number three cold leg accumulator isolation valve was maintained in the correct position. Immediate corrective action was to place the breaker in the correct position. Additional corrective action included reviewing and revising procedures for control of limited evolutions, reviewing Technical Specification interpretations with licensed personnel, and reviewing procedures for event reporting. The inspector reviewed the LER and verified that licensee corrective actions were accomplished.

Within the areas inspected, no violations were identified.

8. Action on Previous Inspection Findings (92701, 92702)

   a. (Closed) URI 327, 328/89-18-02, Completion of Old ECN Closures. The issue involved a licensee commitment in February of 1987 to closeout an ECN backlog of approximately 1,150 by October 15, 1988. The licensee's commitment resulted from NRC concerns in a letter dated December 18, 1986, about a large ECN backlog and its impact on FSAR updates and other issues. The FSAR update process was previously linked to ECN closure and the backlog affected timely FSAR updates. The process was subsequently changed by the licensee to allow the accomplishment of FSAR updates following ECN field completion. The inspectors concern in URI 89-18-02 was that the licensee substituted, not accounted for, or cancelled numerous ECNs from the original number submitted in February of 1987. The inspector reviewed a

letter issued on September 19, 1989 from the licensee which indicated an error was made in the establishment of the 1,150 backlog number in that it was generated from a computer count of outstanding work items which included items other than field completed ECNs. The inspectors concluded that this action was acceptable and did not significantly modify the intent of the original commitment. In addition to the commitment to close the 1,150 ECNs, the licensee reviewed partially complete ECNs prior to the 1988 restart to accurately reflect actual plant equipment changes in the FSAR. Plant procedures were also reviewed to reflect the changes in the same timeframe. Based on the licensee's current ECN closure and FSAR update processes and an acceptable review of the substitutions made in the original 1,150 commitment, the inspectors consider this URI closed.

b. (Closed) VIO 327, 328/89-19-07, Failure to Comply with TS Action Statements. This issue involved the licensee's failure to comply with TS 6.8.1 to properly use procedures, and TS 3.3.1, action statement 2. In the first part of the violation, operators failed to implement AOI-4 to properly remove nuclear instrument N-31 from service. Licensee corrective action was to issue a training letter issued to all licensed personnel to help avoid similar personnel errors in the future. In the second part of the violation, the licensee chose to enter TS 3.0.3 instead of completing the actions required by TS 3.3.1, action statement 2, which resulted in a non-conservative extension of time allowed before reducing unit power. Licensee corrective actions were to issue guidance to licensed operators to ensure appropriate and consistent application of TS 3.0.3, and implementation of a change to clarify TSs 3.2.4 and 3.3.1.1. The inspector reviewed the licensee's responses to the violation and changes to TSs 3.2.4 and 3.3.1.1, and found that the corrective actions have been implemented. Associated issues concerning the availability of procedures for implementing TS required actions, which were discussed in violation-related correspondence, were previously closed in NRC Inspection Report 327, 328/91-06.

Within the areas inspected, no violations were identified.

9. ESF System Walkdown (71710)

During this period, the inspectors conducted a walkdown of both the Unit 1 and Unit 2 Auxiliary Feedwater system. Inspectors verified equipment lineups versus drawings, and then inspected all accessible portions of the system. The system was checked for electrical breaker lineup, valve lineup, and component visual condition. System condition was found in general to be good, with appropriate lineups and material conditions.

However, several minor discrepancies were noted. These included eight isolation valves for P-250 computer pressure transmitters and secondary chemical addition that were shown on system drawings, but were

not included in system standby readiness checklists. Two of these valves were closed and six were open. The facility is continuing to investigate the need to include the valves in the standby readiness checklist, and the preferred position for the valves when at power. Additionally, one system valve was noted as being full open when the checklist required it to be throttled, and this was corrected by the licensee. Three valves were found to be missing labels, and temporary labels were placed on the valves by the licensee. In combination, these discrepancies indicate a weakness in attention to detail in control of system configuration outside of main safety flowpaths. Additionally, in the area of the Unit 1 motor driven AFW pump LCVs, housekeeping was noted to be very poor, with a significant amount of material left from previous work activities in the area.

During the inspection, it was noted that there was a large number of temporary labels on equipment throughout the plant, with some dating back as far as May 13, 1989 (temporary label tag on 2-HS-67-96C). A particular concern noted with the AFW system was the labeling of the MOV board breaker cubicles for 2-FCV-1-15 and -16, and 1-FCV-1-15. The labels for these breakers listed the incorrect SG for the valves (e.g. reads "...Isolation for SG-1", when the valve actually isolates SG-4). Temporary identification tags request forms taped to the breaker cubicles were the only indication to an operator that the labeling was incorrect. Although these valves are required to be operated in several emergency procedures, the tag request forms have remained in place with no apparent action since September 19, 1989. Also, it was noted that contrary to the guidance of SQM2.4, MAINTENANCE MANAGEMENT SYSTEM TEMPORARY IDENTIFICATION TAG REQUEST FORM PROGRAM, REVISION 1, the date blocks on these and several other temporary identification tags had not been completed.

Within the areas inspected, no violations were identified.

10. 10 CFR 50.59 Safety Evaluation Program (40500, 42700)

During the week of January 13 - 17, 1992, a special inspection of the licensee's 10 CFR Safety Evaluation Program was conducted. The following areas were reviewed by the inspection team:

Procedures and Controls

a. The inspector examined the procedure that is used for evaluating changes, tests, or experiments (CTEs) for which 10 CFR 50.59 is applicable. The procedure is also used to determine whether a proposed change involves an unreviewed safety question or a change to the technical specifications. In addition, other procedures that are related to CTEs were evaluated to determine the effectiveness of the overall program.

b. The inspector examined the following procedures which could, potentially, be an integral part of a complete 10 CFR 50.59 program:

(1) Site Standard Practice SSP-12.13, Revision 0, 10 CFR 50.59 Evaluations of Changes, Tests, and Experiments. [This procedure replaced Procedure SSP-27.3 on January 1, 1992].

(2) Site Standard Practice SSP-27.3, Revision 3, Safety Assessment/Evaluation of Changes, Tests, and Experiments (10 CFR 50.59). [This procedure was replaced by Procedure SSP-12.13 on January 1, 1992].

(3) Site Standard Practice SSP-2.3, Revision 3, Administration of Site Procedures.

(4) Site Standard Practice SSP-6.21, Revision 0, Initiation of Work Requests.

(5) Site Standard Practice SSP-6.22, Revision 0, Planning Work Orders.

(6) Site Standard Practice SSP-6.23, Revision 0, Troubleshooting With Work Orders.

(7) Site Standard Practice SSP-6.24, Revision 0, Configuration Control Log.

(8) Site Standard Practice SSP-6.25, Revision 0, Performance of Work Orders.

(9) Site Standard Practice SSP-6.26, Revision 0, Completion of Work Orders.

(10) Site Standard Practice SSP-6.28, Revision 0, Status Tracking For Work Orders.

(11) Site Standard Practice SSP-6.29, Revision 0, Initiation of Service Requests.

(12) Site Standard Practice SSP-6.30, Revision 0, Generic Design Change Notice Work Order Package.

(13) Sequoyah Engineering Procedure SQEP-26, Revision 12, Design Change Control.

(14) Administrative Instruction AI-9, Revision 33, Control of Temporary Alterations and Use of the Temporary Alterations Order.

(15) Administrative Instruction AI-19 (Part VI), Revision 16, Modifications: Permanent Design Change Control Program.

(16) Site Standard Practice SSP-4.2, Revision 0, Management of the Final Safety Evaluation Report (FSAR).

c. The inspector noted that Procedure SSP-12.13, Revision 0, had been implemented only a few days prior to the inspection and that it replaced Procedure SSP-27.3. The licensee explained that the changes to the new procedure were not technical in nature and that all controls related to the 10 CFR 50.59 process were contained in both procedures. Therefore, Procedure SSP-12.13 was used to evaluate the present program. However, program implementation was evaluated using the procedure that was in effect when the safety assessments/safety evaluations were written (SSP-27.3). This difference was judged to be inconsequential to the evaluation.

d. The following inspector comments concerning the 10 CFR 50.59 program were resolved with the licensee:

(1) A Site Qualification Review Board reviews all candidates before they become qualified as Level II Reviewers of Safety Assessments/Safety Evaluations. However, the procedure does not require that the Board contain an individual who has received formal training in the 10 CFR 50.59 process. The licensee showed that by virtue of the positions of the Board members (high level site management), a satisfactory mixture of expertise and experience is attained.

(2) SSP-12.13 contains a list of personnel that are qualified to perform Level I and Level II functions, and is periodically updated as personnel changes occur. However, this updating process is not formalized. In addition, the list can be updated separately from the procedure update, and no mechanism exists to determine if any given copy of the procedure contains the latest list of qualified personnel. Prior to the exit, the licensee added a revision number to the qualification list and committed to review the list to ensure its accuracy.

(3) Several procedures (such as those related to Work Requests) did not indicate that a 10 CFR 50.59 evaluation may be necessary prior to performing the work described. However, the licensee explained that the work addressed by the procedure would be a part of a larger Work Package, which would contain the 10 CFR 50.59 evaluation, if one was necessary.

(4) The procedure does not indicate the retraining interval for Level I preparers, which is left to the discretion of the Program Manager. The licensee committed to determine the desired retraining frequency and add it to the procedure.

(5) The Temporary Alterations procedure requires review of all outstanding Temporary Alteration Control Forms (TACFs) when they become a year old. This review is designed to, among other things, ensure that the safety analysis is still valid. However, the procedure does not require that this review be conducted by a Level I or a Level II qualified person. In

addition, the procedure does not require that the latest revision to the safety analysis procedure be used for the calculation. The licensee committed to determine the desired qualification level for the personnel performing the annual reviews and to evaluate the annual review requirements.

e. Observations

(1) There appears to be an excessive number of personnel qualified as Level I preparers (approximately 350) of safety evaluations. It could be difficult to ensure that the high level of practical experience needed for this function is maintained for this number of personnel.

(2) Procedure SSP-12.13 appears to allow excessive use of "N/A" in the safety assessments/safety evaluations and does not describe how its use fits into the final evaluation of a planned change, test, or experiment.

(3) A Justification for Continued Operation (JCO) procedure that would be used to justify operation under some plant conditions, has been prepared but not yet reviewed and issued. Its planned interface with the 10 CFR 50.59 process was briefly discussed with the licensee and should be implemented as soon as possible. It will be reviewed following implementation.

f. As a result of the inspection of procedure implementation, it was determined that the program to address the requirements of 10 CFR 50.59 was well structured, and that use of the procedures should result in safety reviews that adequately address the requirements of 10 CFR 50.59. The program makes extensive use of the related industry document, NSAC-125, "Guidelines for 10 CFR 50.59 Safety Evaluations," prepared by the Electric Power Research Institute.

Qualification and Training

a. Level I preparers are TVA and contractor personnel whose job assignments involve them in the preparation and processing of safety assessments/safety evaluations as required by the 10 CFR 50.59 program. Level II Reviewers review the safety evaluations prepared by the Level I personnel prior to management approval. Level II Reviewers must be Level I qualified and, therefore, must receive the initial Level I training course. This program appears to be well organized and effective, and appeared to result in personnel that performed safety assessments and evaluations that were generally found to be comprehensive and factual.

b. SSP-12.13 requires that Level II Reviewers be approved by the Qualification Review Board prior to becoming qualified. However, the inspector was concerned that the board members listed in the procedure are not required to receive the Level I training. The

licensee explained the board consists of experienced high-level managers of the functions to which Level I and Level II personnel are assigned, as well as other disciplines. This was determined to be acceptable.

c. The inspector attended a retraining class being conducted in accordance with SSP-12.13 for Level 1 Preparers and Level II Reviewers (21 personnel) of 10 CFR 50.59 evaluations. In addition, the lesson plan and the subsequent examination were reviewed. The instructor appeared to be well versed in the procedural requirements of safety assessments/safety evaluations and was able to communicate the information effectively. Class participation and interest in the subject was evident. The course material appeared to cover 10 CFR 50.59 adequately and the exam was satisfactory.

Program Implementation

a. The inspectors reviewed five (approximately 20 percent) of the current active plant temporary alteration safety evaluations, approximately fifteen 10 CFR 50.59 safety evaluations associated with selected plant modifications, and approximately twenty evaluations associated with procedure changes or revisions.

b. The following Temporary Alterations safety assessments were reviewed and appeared to be satisfactory:

(1) 2-91-30-055, Annunciator Power Supplies.

(2) 0-91-0043-244, Communications for Telephones and IBM 3741 Controller.

(3) 2-91-36-068, Pressurizer Relief Tank Temperature High Alarm.

(4) 1-90-35-062, Venting Equipment Connected to Valves 1-62-999; 1-63-599, 707, and 708.

(5) 2-91-32-056, Morgan Temperature Monitor, 2-TM-56-2, Rack 112.

However, a review of the temporary alterations (TAs) that were currently in effect, as indicated by maintenance of the Control Room log book, resulted in detection of the following discrepancies:

(1) Four TA forms were in the logbook, but were not listed on the logbook index. This could be significant since the index is used to review the status of outstanding TAs. The licensee determined that extra copies of these TAs had inadvertently not been removed from the logbook when the originals were cleared. The licensee agreed to evaluate the control of extra copies of TAs in the logbook.

(2) One current TA form was in the logbook without a completed safety assessment/evaluation. Therefore, it could not readily be determined that the required evaluation had been performed. The licensee subsequently determined that the evaluation had been performed and attached a copy to the TA form in the logbook.

(3) Four examples were noted where individuals listed on the TA log index as performing certain activities associated with a particular TA did not agree with those individuals listed on the TA who actually performed the activity. The licensee corrected the index.

After these discrepancies were identified to station management, the licensee conducted a comprehensive review of the logbook and detected several additional errors. A problem evaluation report (SQPER920011) was generated. The inspectors consider these findings to be an example of a lack of attention to detail in administering the temporary alteration program. The inspectors will closely monitor licensee corrective actions in this area during future inspection activities.

c. Review of modification package safety assessments provided the following:

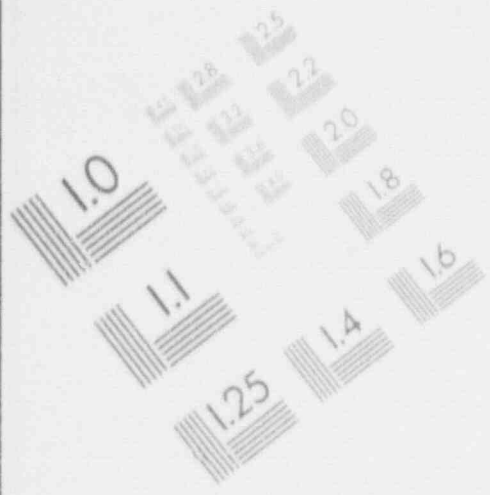
(1) Plant Modification ECN L6189, Upgrade Incore Thermocouple Monitoring Equipment, and DCN M-00555-A, Physical Modification to Pipe Supports as Indicated, determined that the initial 10 CFR 50.59 evaluations had been performed prior to implementation of the specific requirements of Procedure SSP-27.3. However, subsequent revisions of the evaluations that were performed after implementation of SSP-27.3, Revision 3, were not updated to the current format. Following discussions with the licensee, the inspector concluded that the requirements of 10 CFR 50.59 were being accomplished even though the review process for older DCNs was not formally addressed in a procedure. The licensee agreed to evaluate the concern.

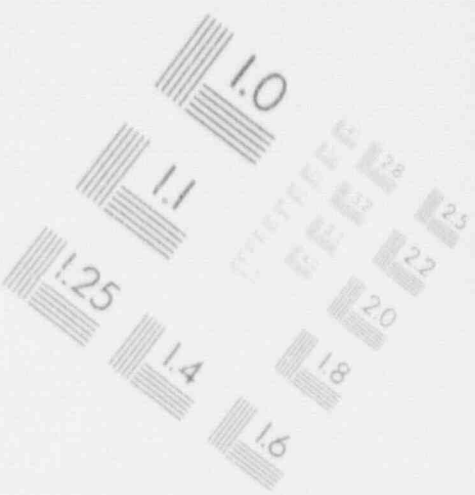
(2) Initial inspector review of DCN M-04041-A, Pipe Support Modification Required Due to Reanalyzing of MSIV Bypass Lines, determined that a safety assessment preparer for Revision 2 could not initially be verified as qualified in accordance with Procedure SSP-27.3. Additional record reviews resulted in the determination that the proper verification existed.

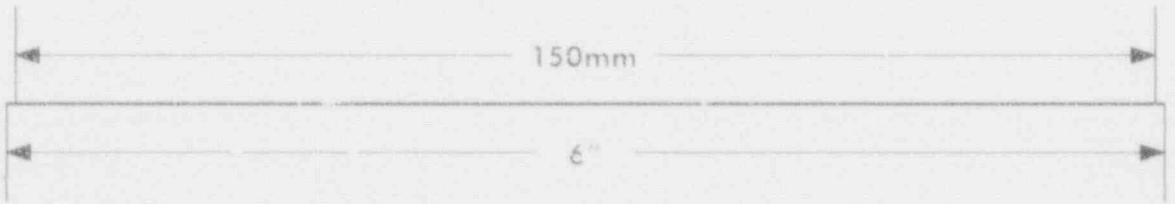
(3) Inspector review of DCN M-06269-A, Replacement of Main Control Room Annunciator System for Unit 1 and Common Panels, determined that details for the justification of some of the safety assessment review criteria appeared to lack thoroughness. This conclusion had also been identified in a licensee QA audit, which should result in adequate resolution by the licensee.

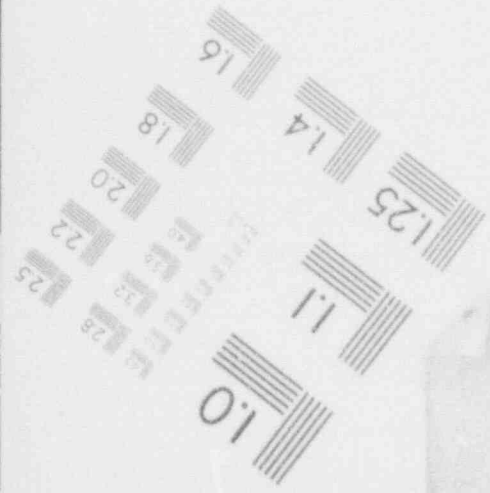
1

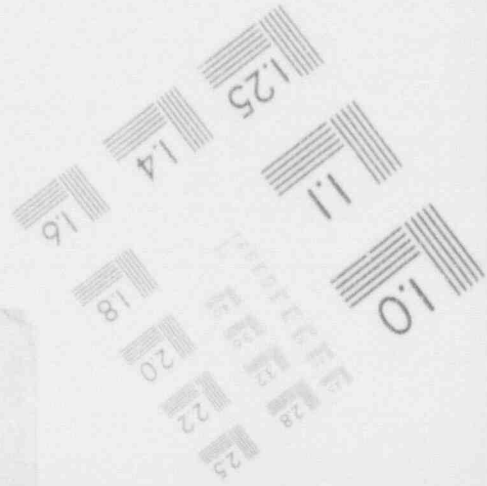
IMAGE EVALUATION TEST TARGET (MT-3)

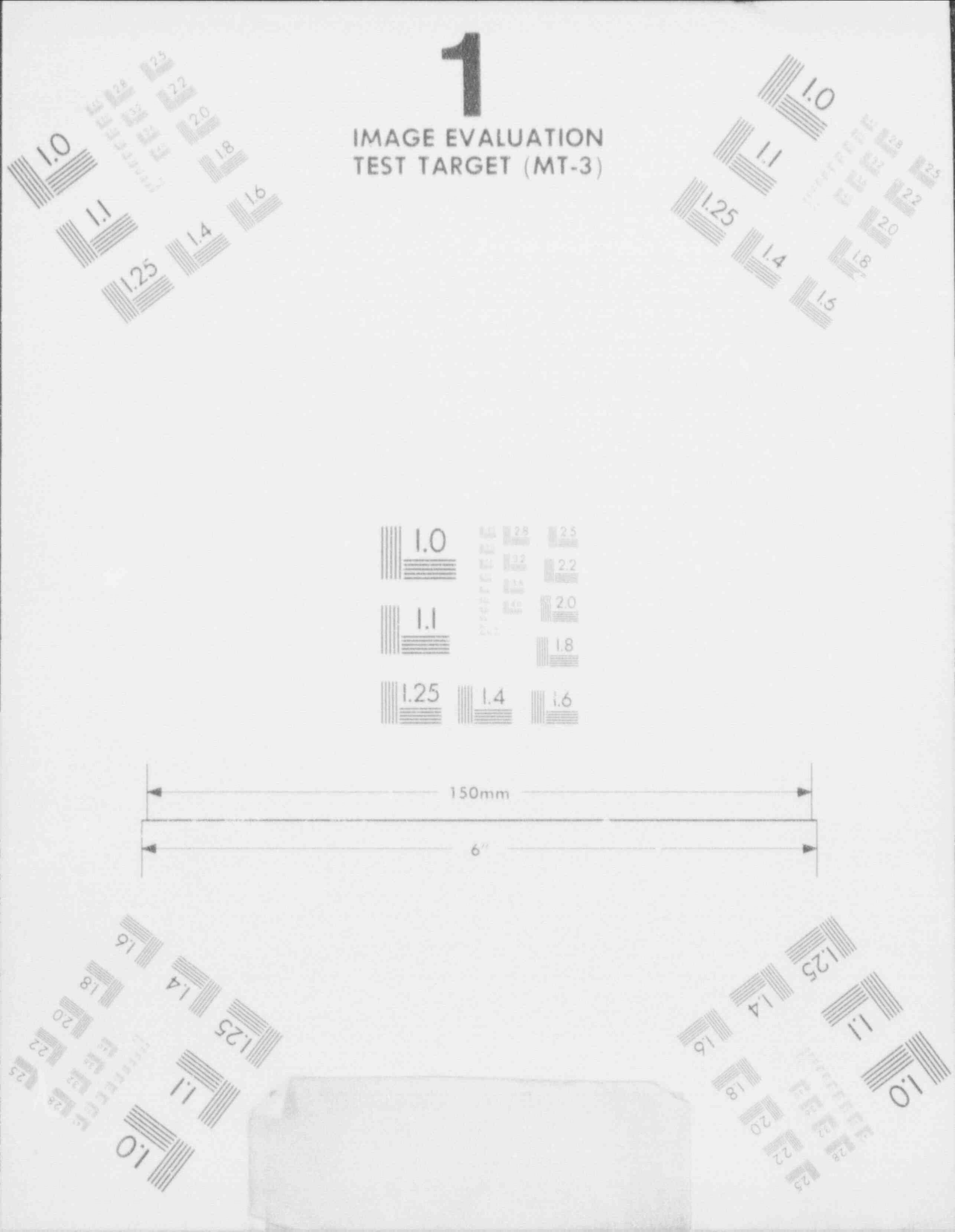






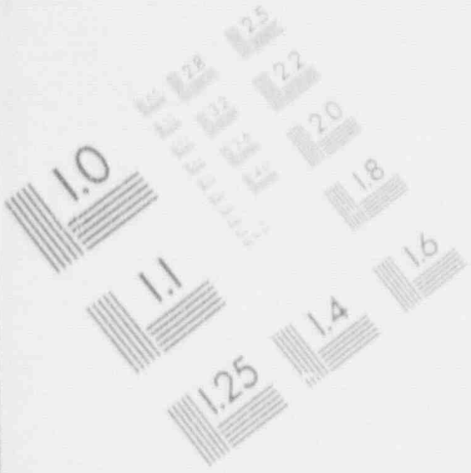


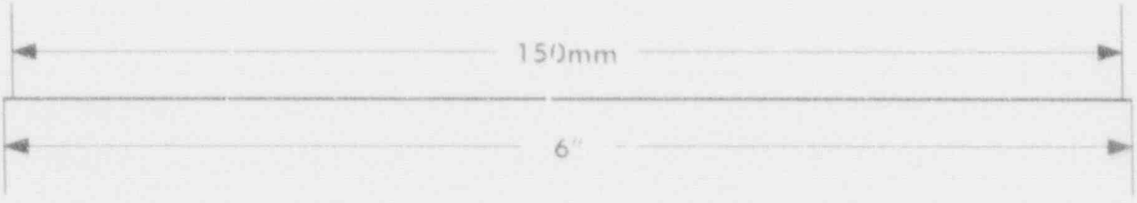


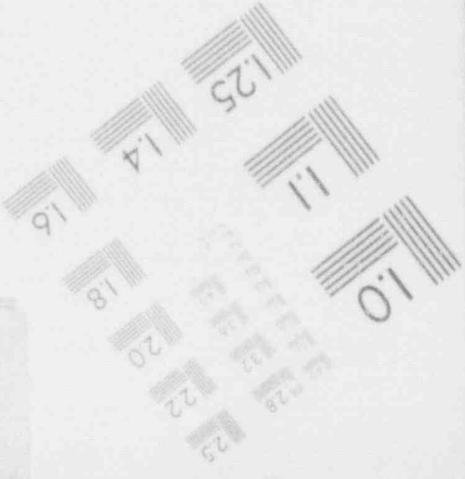

1
IMAGE EVALUATION
TEST TARGET (MT-3)
1.0
1.1
1.25
1.4
1.6
1.8
2.0
2.2
2.5
150mm
6"

1

IMAGE EVALUATION
TEST TARGET (MT-3)







(4) The inspector noted a lack of consistency of the review and approval signatures format for revisions to the safety assessment/evaluations in DCN M-05407-A, Modification to Valve FCV-63-172, Drilling 3/16" Hole in the Downstream Side of Valve Wedge, and in DCN M-06227-A, Removal of Interfaces to Allow Installation of Component Cooling Heat Exchangers 1A1/1A2 and Associated Piping.

d. The following modification package safety assessments were reviewed and appeared to be satisfactory:

(1) DCN F-08086-A, Modify Annunciation Indication/Alarm for Containment Air Lock Door Status.

(2) DCN M-06634-B, Replacement of MOV Torque Switch Spring Packs for System 68 Valves.

(3) DCN M-062295-B, Implementation of Rigi-Flex Generator Stator Rewind Project.

(4) DCN M-05420-A, Installation of Check Valves in RHR Pump Miniflow Lines.

(5) DCN M-01978-A, Revise Unit 1 Pipe Support Calculations and Provide Physical Modifications for Pipe Supports Inside Unit 1 Containment.

(6) DCN M-06203-B, Elimination of Nuisance Alarms in the Main Control Room.

(7) DCN M-06775-A, Installation of Replacement High Head Rotating Element in CCP 1A-A.

(8) DCN M-06641-A, Replace Flow Orifices in Unit 1 ERCW Main Headers.

(9) DCN M-07872-A, Replace 13 Control Cables for Main Generator CT Outputs.

e. The following safety assessments associated with procedure changes were reviewed and comments generated:

(1) AI-56, Criteria for the Erection of Scaffolds Including Those in Seismically Qualified Structures, Revision 0.

No specific guidance is provided to ensure that human factor considerations are factored into scaffold placement in the plant during times when components around the scaffold were considered to be operable or operating. For example, guidance concerning interferences that might prevent or hamper operators performance of duties in the

vicinity of scaffolds during emergencies, or interference with ventilation, was not provided. The inspector discussed these specific areas with the licensee and determined that these human factors issues were not considered during preparation or review of the safety assessment. The licensee agreed to evaluate the concern. The inspectors will review the licensee's resolution during upcoming routine inspections.

(2) 1-SI-OPS-070-032A, Component Cooling Water Valves Position Verification Train A, Revision 1.

No reviewer or approver signatures appear on Revision 1 of the safety assessment due to oversight. The licensee provided additional information that allowed the inspector to conclude that the safety assessment for Revision 1 had been reviewed and approved as required.

(3) TI-28, Curve Book, Revision 1.

The revision number procedure TI-28 did not agree with the revision number of the procedure logged on the attached safety assessment. It was concluded that the safety assessment was the correct safety assessment for the procedure change, but that the incorrect revision number was entered on the safety evaluation form. The licensee reviewed this minor discrepancy for appropriate action.

(4) An additional 17 safety assessment/evaluation packages associated with procedural changes or revisions in maintenance, operations, and technical support areas were reviewed. No additional concerns resulted.

The inspector concluded that the licensee implementation of the program for compliance with 10 CFR 50.59 was comprehensive and that the reviews were being accomplished in a satisfactory manner. The inspector categorized the discrepancies noted above as examples of a lack of attention to detail.

Annual FSAR Update

a. The inspector reviewed SSP-4.2, which is used to update the FSAR, and observed the audit trail for processing FSAR changes.

b. In accordance with SSP-4.2, change packages consisting of ECNs/DCNs (i.e., candidate changes to the FSAR) are transmitted to the TVA regulatory licensing manager where the pertinent data from the package is transcribed to a control sheet, which constitutes a part of the "living FSAR." The control sheet tracks the steps necessary to evaluate and process a change package to ensure it is included in the FSAR update, if a change is needed.

c. At the time of the inspection, there were 31 change packages that will input into the "living FSAR" and be included in the 1991 FSAR update, which is scheduled to be submitted on April 15, 1992.

d. The inspection revealed that several sources are used for input to a final annual FSAR update submittal. This creates administrative difficulties due to the timing of the submittal in relation to the various plant changes, and the interface of the FSAR submittal with the Annual Operating Report of plant changes, tests, and experiments that must be submitted at the end of the year, in accordance with 10 CFR 50.59(b)(2). Specifically: The next Annual Operating Report submittal covers the period from January 1, 1991 to December 31, 1991, and is scheduled to be submitted in March 1992. In contrast, the next FSAR annual update covers the period from the last update until October 15, 1991, and will be transmitted on April 15, 1992. It is, therefore, evident that the "living FSAR" is a critical file for auditing the accuracy of the FSAR update. The licensee's process for controlling these evolutions appears to be effective, however.

Annual Operating Report per 10 CFR 50.59(b)(2)

a. In accordance with 10 CFR 50.59(b)(2), each licensee is required to submit an Annual Operating Report that contains a brief description of changes, tests, and experiments, along with a summary of the safety evaluation for each.

b. The last TVA submittal covers the period from January 1, 1990 to December 31, 1990.

c. The inspector expressed a concern that the summaries of the descriptions and safety evaluations contained in the report were too brief and contained too little factual information. The licensee agreed to revise future submittals to include more information.

d. The inspector also expressed concern regarding the following statement that is contained on the criteria page of the report: "Temporary alterations to the facility are reported if they remained open December 31, 1990." The inspector was concerned that the licensee may not be reporting temporary alterations that were started and closed within the year. The licensee could not determine why this statement is made, nor if it formed the basis for excluding information in the submittal. The licensee agreed to submit, in the next Annual Operating Report, all temporary alterations to the facility that were made during the respective report period, regardless of the status of the temporary alteration at the end of the year.

Within the areas inspected, no violations were identified.

11. Exit Interview

The inspection scope and results of the 10 CFR 50.59 inspection were summarized on January 17, 1992 with those individuals identified by an asterisk in paragraph 1 above. The inspection scope and results of routine resident inspection were summarized on February 5, 1992 with those individuals identified by an # in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
327, 328/92-02-01	Violation of TS 6.8.1 for failure to follow the requirements of SSP-10.1 (paragraph 3.a).
327, 328/92-02-02	NCV for failure to follow the requirements of SOI-78.1 (paragraph 3.b).
327, 328/92-02-03	NCV for failure to follow the requirements of 10 CFR 55.53.(e) and AI-30 (paragraph 3.c).

Strengths and weaknesses summarized in the results paragraph were discussed in detail.

Licensee management was informed of the items closed in paragraphs 7 and 8.

12. List of Acronyms and Initialisms

AI - Administrative Instruction
AFW - Auxiliary Feedwater
ALARA- As Low As Reasonably Achievable
AOT - Allowed Outage Time
ASME - American Society of Mechanical Engineers
AUO - Auxiliary Unit Operator
CAQR - Condition Adverse to Quality Report
CCP - Centrifugal Charging Pump
CDWE - Condensate Demineralizer Waste Evaporator Building
CFR - Code of Federal Regulations
CT - Current Transformer
CVCS - Chemical and Volume Control System
DC - Direct Current
DCN - Design Change Notice
DRP - Division of Reactor Projects

ECN - Engineering Change Notice
EDG - Emergency Diesel Generator
EOL - End of Life
ERCW - Essential Raw Cooling Water
ESF - Engineered Safety Feature
FSAR - Final Safety Analysis Report
KV - Kilovolts
LCO - Limiting Condition for Operation
LCV - Level Control Valve
LER - Licensee Event Report
MI - Maintenance Instruction
MOV - Motor Operated Valve
MSIV - Main Steam Isolation Valve
NCV - Non-cited Violation
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
PERP - Plant Evaluation Review Panel
PER - Problem Evaluation Report
PMT - Post Maintenance Test
RHR - Residual Heat Removal
R-II - Region II
QA - Quality Assurance
QC - Quality Control
RCS - Reactor Coolant System
RHR - Residual Heat Removal
RM - Radiation Monitor
PRT - Pressurizer Relief Tank
RWP - Radiation Work Permit
SDT - Shutdown Time
SSP - Site Standard Practice
SI - Surveillance Instruction
SOI - System Operating Instruction
SOS - Shift Operating Supervisor
SRO - Senior Reactor Operator
TS - Technical Specifications
TSC - Technical Support Center
TVA - Tennessee Valley Authority
URI - Unresolved Item
WO - Work Order
WR - Work Request