U. S. NUCLEAR REGULATORY COMMISSION (NRC)

REGION II

Docket Nos. 50-424 and 50-425
License Nos. NPF-68 and NPF-81

Report No:	50-424/97-10, 50-425/97-10
Licensee:	Southern Nuclear Operating Company, Inc.
Facility:	Vogtle Electric Generating Plant (VEGP) Units 1 and 2
Location:	7821 River Road Waynesboro, GA 30830
Dates:	September 21, through November 1, 1997
Inspectors:	M. Widmann, Acting Senior Resident Inspector K. O'Donohue, Resident Inspector R. Caldwell, Resident Inspector, Farley (Sections E8.1, E8.2 and E8.3) C. Rapp, Project Engineer (Sections 08.3 and E3.1) W. Kleinsorge, Reactor Inspector, Region II (Sections M1.3, M1.4, and M1.5)
Approved by:	P. Skinner, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure 2

EXECUTIVE SUMMARY

Vogtle Electric Generating Plant Units 1 and 2
NRC Inspection Report 50-424/97-10, 50-425/97-10

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection. It also includes the results of an announced inspection by a regional maintenance inspector.

Operations

- Plant management's conservative decision making was demonstrated when the licensee elected to avoid a fueled midloop during 1R7 (Section O1.1).

- Performance of startup activities from the Unit 1 refueling outage were in accordance with procedures (Section O1.3).

- Opening the reactor trip breakers in response to the Digital Rod Position Indication (DRPI) was appropriate during startup testing on Unit 1 (Section O1.4).

- An example of poor work practices was identified that resulted in an inadvertent dilution event during a demineralizer flush activity (Section O1.5).

- The reactor operators' response to the indicated plant conditions and the resultant transient was excellent (Section O1.5).

- Another example of poor work practices was identified when a lack of communications resulted in failure to properly block a containment radiation monitor. This activity resulted in an inadvertent emergency features actuation (Section O1.6).

- The Emergency Safety Features (ESF) systems reviewed were available to perform their intended design function, were properly aligned, and Technical Requirements Manual (TRM) commitments and Technical Specifications (TS) requirements were met (Section O2.1).

- A violation was identified for improper control and alignment of diesel generator unit heater 480-volt breakers (Section O2.2).

- A weakness was identified for multiple examples of a failure to properly review procedure revisions in accordance with an established procedure. The procedure revision errors directly impacted the operation of the plant during performance of these procedures (Section O3.2).

- A weakness was identified for the operations crew in not recognizing that Unit 1 entered and exited a TS Limiting Condition for Operation for an emergency core cooling system (Section O3.2).

- The licensee was in compliance with TS requirements for plant staff hours (Section O8.1).
- The licensee's implementation of a new program to clean the containment prior to the performance of a closeout exit inspection has adequately addressed previously identified loose debris issues and should preclude repetition. The increased emphasis that the licensee placed on material control within containment during 1R7 achieved successful results (Section O8.2).

Maintenance

- A non-cited violation related to failure to follow a magnetic particle examination (MT) procedure was identified (Section M1.3).
- Inservice inspection activities observed/reviewed were conducted in accordance with procedures, licensee commitments, and regulatory requirements (Section M1.3).
- The licensee's programmatic coverage of arc strikes was considered a weakness (Section M1.3).
- Unit 1 steam generator #4 tubesheet rework activities were supported by appropriate evaluations and controlled by well written procedures and highly trained and motivated individuals (Section M1.4).
- Unit 1 split pin replacement activities were supported by appropriate evaluations and controlled by well written procedures and highly trained and motivated individuals (Section M1.5).
- Troubleshooting efforts implemented during outage work involved the proper personnel, procedures and work orders were developed in a timely manner, and activities performed were in accordance with procedure guidance (Section M1.6).
- Diesel Generator Train A and B and engineered safety features actuation system (ESFAS) testing were performed in accordance with written procedures and were well controlled (Section M3.1).
- Emergency Core Cooling System Flow Test, performed in accordance with written procedures which incorporated a new testing method, was well controlled (Section M3.2).
- A non-cited violation was identified for maintenance calibration procedures implemented during the outage that left instrument setpoints outside the trip setpoints stated in technical specifications (Section M8.1).

Engineering

- The licensee's design change package (DCP) 97-V1N0022 was complete and sufficiently detailed, and implementation of the valve modification during the Unit 1 seventh refueling outage (1R7) was satisfactory (Section E2.1).

- A violation was identified for the licensee not fully implementing developed corrective actions for use of the APEX users manual prior to the startup of Unit 1 (Section E3.1).

- The licensee review for LER 50-424/96-005 was not adequate in that it did not identify the full scope of the Eaton Cable splicing issue (Section E8.1).

- A weakness was identified in the area of deficiency card review process for the lack of clear guidance for the determination of Maintenance Preventable Functional Failures (Section E8.3).

Plant Support

- The removal and storage activities for the lower guide tube were well controlled, coordinated, and in accordance with the vendor procedure. Worker precautions were appropriate. The licensee's awareness of radiological and personnel safety associated with this activity was identified as a strength. (Section R1.1).

- A non-cited violation was identified for a contract worker leaving the plant after performance of a self-decontamination activity (Section R3.1).

Report Details

Summary of Plant Status

Unit 1 began the inspection period defueled. Mode 6 was entered October 8, 1997, fuel reload and core verification was completed October 13. On October 20, mode 2 was entered, the unit was taken critical, and low power physics testing performed. Mode 1 entry occurred October 22 at 0024, the unit output breakers were closed at 2258 the same day. Power ascension followed. The inspection period ended with Unit 1 at 100% power.

Unit 2 operated at full power throughout the entire inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the reviews indicated that the conduct of operations was satisfactory.

On approximately October 10, 1997, the inspectors were informed that the licensee had elected not to enter a reduced inventory condition with fuel in the vessel. Instead, the licensee elected to incur approximately 28 hours of critical path time in the outage thereby obviating the need for a fueled midloop. The inspectors concluded that this was a conservative decision on the part of plant management.

O1.2 Core Reload (60710)

The inspectors observed the majority of the Unit 1 fuel reloading activities. The inspectors reviewed Procedures 93300-C, "Conduct of Refueling Operations," Revision (Rev.) 17, and 93100-C, "Refueling Tools and Equipment Preservice Inspection/Checkout," Rev. 8. In addition, the inspectors observed the site reactor engineering initial core verification activities and portions of the second verification (i.e., reactor engineering personnel compared the video tape recorded during initial verification activities to the reshuffle plan).

Based on this review the inspectors concluded that the licensee reloaded the core in accordance with their reshuffle plan. Refuel activities were performed in a controlled manner and in accordance with specified procedures. No discrepancies were identified by the inspectors during the reload process.

O1.3 Unit 1 Startup Observations (71707)

The inspectors observed selected portions of the Unit 1 startup coming out of 1R7. Activities observed by the inspectors included the entry to mode 6, core reload, entry into modes 5, 4, and 3, rod drop tests, plant heatup, reactor thermocouples cross calibrations, transition into mode 2, low power physics testing, and power escalation in preparation for turbine loading. The performance of these evolutions were in accordance with procedures.

O1.4 Manual Reactor Trip

a. Inspection Scope (71707)

The inspectors reviewed the circumstances surrounding the Unit 1 manual reactor trip of October 19. During the performance of Procedure 88006-C, "Rod Drop Time Measurement with Rod Drop Test Cart," Rev. 7, the reactor trip breakers were manually opened due to inappropriate rod alignment indication. The inspectors reviewed the shift briefing notes, log entries, applicable procedures, and the Technical Requirements Manual (TRM). The inspectors interviewed the operations personnel involved and discussed the trip with licensee management.

b. Observations and Findings

While in mode 3, the reactor trip breakers were closed to allow for hot rod drop testing per Procedure 88006-C. Shutdown bank "A" was being withdrawn for the test. The Digital Rod Position Indication (DRPI) system was expected to alarm during the withdrawal due to a previously identified DRPI coil deficiency. Rod M-2, part of shutdown bank "A", had a malfunctioning data "B" coil such that when that rod was approximately 48 to 52 steps withdrawn the DRPI indication became erratic. DRPI alarms and indication were expected to return to normal status once the rod was pulled through that step range. This expectation was based on previous experience with the malfunctioning coil.

During the hot rod testing DRPI alarms came in as expected, however, they did not clear once the shutdown bank was withdrawn past step 52. Because indication discrepancies for Rod M-2 were anticipated the reactor operator continued to withdraw the shutdown bank. Once past step 52, the DRPI rod bottom light for Rod M-2 cleared, however, the indicated position for Rod M-2 was identified as being beyond the required alignment of 12 steps. After stopping the withdrawal of shutdown bank "A", the reactor operator identified the difference between Rod M-2 and the rest of the bank to be greater than 12 steps and opened the reactor trip breakers as required by TRM 13.1.9, "Test Exceptions for Position Indication System-Shutdown," Action Statement "A". This event was reported per 10 CFR 50.72 as a reactor protection system actuation (four-hour notification).

c. Conclusions

The inspectors concluded that opening the reactor trip breakers in response to the DRPI was appropriate.

O1.5 Inadvertent Dilution

a. Inspection Scope (71707)

During the reactor startup, the inspectors observed that reactivity additions were generally well coordinated and involved appropriate oversight on the part of the licensed operators with the exception of an inadvertent dilution which took place October 21. As a result of the event, the inspectors reviewed Procedure 13009-1, "Chemical Volume and Control System Reactor Makeup Control System," Revision 19; 13701-1, "Boric Acid System," Revision 18, control room logs, computer graphs and calculation sheets.

b. Observations and Findings

On October 21, 1997, Unit 1 in mode 2 at approximately 2% power. During flushing of the Chemical Volume and Control System (CVCS) mixed bed demineralizer #3, an inadvertent dilution occurred that resulted in a power increase of 2.6%. However, when the reactor operator observed the unexpected power increase, control rods were immediately inserted and the Reactor Coolant System (RCS) borated to return reactor power to the initial level of 2%. Computer data indicated that reactor power went from approximately 2% to 4.6%.

The inspectors identified that on October 20, 1997, the Boric Acid Storage Tank (BAST) received boric acid makeup throughout the night. Night shift personnel placed the BAST in recirculation at 5:00 a.m. on October 21. At 7:00 a.m., it was noted during shift turnover that the BAST required additional makeup. Operations personnel continued to makeup to the BAST during the morning of October 21 while the BAST was in recirculation. Chemistry was not contacted to take a sample for boron concentration from the BAST during or after the makeup activities.

At 1:00 p.m. October 21, the CVCS demineralizer #3 was flushed prior to being placed in service to ensure the demineralizer was at the current RCS boron concentration. As part of the flushing process the CVCS letdown flow was diverted to the recycle holdup tank. As a result of the letdown flow diversion, the Volume Control Tank (VCT) level decreased. Volume Control Tank level was manually restored using a blended flow from the BAST and Reactor Make-up Water Storage Tank (RMWST). The operators calculated the ratio of boric acid to demineralized water based on the BAST boron concentration that was posted on the control board. It was later determined that the boron concentration posted in the control room was from a chemistry sample that was analyzed prior to the initial makeup to the BAST. After response to the inadvertent dilution, the licensee determined that the actual BAST boron concentration was lower than the boron concentration posted in the control room.

The BAST boron concentration sample data was not discussed during shift turnover, therefore, makeup calculations were based on the last known sample. Chemistry sampling measured the actual BAST boron concentration on October 21 to be 6986 parts per million (ppm) The concentration used by the operators to calculate the quantity of acid to be added to the RCS was based on a sample taken October 17. The difference between the actual concentration of October 21 and the sample of October 17 was 489 ppm. This error resulted in a makeup ratio that consequently diluted the RCS boron concentration, adding positive reactivity, and directly causing reactor power to increase. The licensee formed an event review team to examine the inadvertent dilution and identify any appropriate corrective actions.

During review of this event, the inspectors determined that making up to the BAST during the required post-addition 10 hour tank recirculation was not procedurally prohibited. However, making up during BAST recirculation negates the intent of the post-addition 10 hour tank recirculation. Batching during recirculation prevents the BAST volume from being properly "turned over" which prevents sampling from depicting actual plant conditions.

c. Conclusions

The inspectors concluded that the inadvertent dilution event and resultant power increase on October 21, 1997, was the result of poor work practices by operations personnel in conjunction with out dated chemistry sampling data. This issue is identified as an example of poor work practices. The inspectors also concluded that the reactor operators' response to the indicated plant conditions and the resultant transient was excellent.

O1.6 Control Rod Drive Shaft Activity Results in Inadvertent Emergency Safety Feature (ESF) Actuation

a. Inspection Scope (71707)

On October 14, 1997, during removal of a control rod drive shaft from inside containment, a Containment Ventilation Isolation (CVI) signal was received in the Unit 1 main control room. The inspectors reviewed the circumstances surrounding this ESF actuation. The inspectors reviewed the event notification worksheet and the event report investigation. The inspectors also discussed the incident with cognizant operations personnel.

b. Observations and Findings

During an activity to remove a suspected damaged control rod drive shaft from containment, the control rod drive shaft was moved in close proximity to radiation monitor 1RE-002 and a CVI occurred. The plant was in mode 6 at the time of the event. The radiation monitor actuation setpoint was 15 mrem/hour. Maximum radiation readings recorded were approximately 25 mrem/hour. All ESF components actuated as required.

Based on the licensee's investigation, this incident occurred as a result of poor communication between workers inside containment and operations personnel in the control room. During a pre-job briefing the licensee designated a worker inside containment to contact the control room prior to the control rod drive shaft being lifted. The communication was to prompt operations personnel to place radiation monitors located inside containment in the "block" position to avoid a CVI signal. That communication did not occur. A Licensee Event Report (LER) is being developed by the licensee.

c. Conclusions

The licensee determined that the incident was a result of cognitive personnel error. The poor communication associated with this event is identified as another example of poor work practices.

O2 Operational Status of Facilities and Equipment

O2.1 Safety-Related Walkdowns (71707)(61726)

a. Inspection Scope

The inspectors walked down the following ESF systems as part of the routine inspection effort to verify availability and overall condition of the safety-related systems:

Unit 1 Essential Chilled Water System, Train A
Unit 2 Essential Chilled Water System, Train B
Unit 1 Residual Heat Removal System, Train A and B
The inspectors also performed a review of TRM and Technical Specifications (TS) requirements for the above listed systems.

b. Observations and Findings

The inspectors verified proper system configurations both electrically and mechanically for the above ESF systems through accessible portions in the plant, walkdowns of main control room boards, and reviews of system drawings and procedures. The inspectors also observed overall material condition of system components during the walkdowns. The inspectors identified some minor issues which were provided to the licensee for resolution.

c. Conclusions

The inspectors concluded that the systems reviewed were available to perform their intended designed function; systems were properly aligned; and TRM commitments and TS requirements were met. No significant items or discrepancies were noted during these observations.

O2.2 Unit 1 Diesel Generator 480-Volt Breakers Mis-Positioned

a. Inspection Scope (71707)

As part of the core module inspection the inspectors conducted system alignment walkdowns. The inspectors reviewed procedure lineups and systems drawings. The inspectors compared actual breaker positions on motor control center (MCC) 1NBG with the required positions specified in Procedures 11145-1, "Diesel Generator Alignment," Rev. 11; Procedure 11429-1, "480V AC 1E Electrical Distribution System Alignment," Rev. 13; and 11430-1, "480V AC Non 1E Electrical Distribution System Alignment," Rev. 12. The inspectors also discussed the issue with cognizant operations management.

b. Observations and Findings

On October 3, 1997, the inspectors conducted a walkdown of the 480-Volt breakers on MCCs 1NBG, 1NBI, and 1ABF which were located inside the Unit 1 Diesel Generator (DG) train A building. All load equipped breakers were properly positioned with the exception of breakers on 1NBG. Specifically, Procedure 11430-1 required that breakers in MCC 1NBG be closed unless tagged. The inspectors observed that 10 unit heater breakers were open and not tagged.

The inspectors determined from a review of the clearance database that the unit heater breakers were not under clearance when the MCC 1E and Non-1E lineups were last completed.

The licensee informed the inspectors that the licensee's subsequent review of the breaker alignments determined that during the seventh refueling outage various maintenance work was performed on DG 1A. During one of those activities maintenance personnel requested that the unit breakers be turned "off" due the heaters unnecessarily cycling. The request was communicated to operations personnel, but was not logged or controlled in accordance with the plant approved procedure 00304-C, "Equipment Clearance and Tagging," Rev. 36. As a result, no mechanism was in place to ensure that the unit heater breakers, at the conclusion of the maintenance activity, were re-aligned in accordance with electrical system lineup procedure 11430-1. The failure to properly position the DG 1A unit heater breakers on MCC 1NBG in accordance with the requirements of Procedure 11430-1 was identified as Violation (VIO) 50-424/97-10-01, Mis-Positioned Unit Heater Breakers On 480-Volt MCC 1NBG.

The licensee determined that the breakers were mis-positioned for approximately three days until identified by the inspectors. The inspectors noted that plant operators had performed their area rounds for those specific three days and did not recognize or question the breaker positions.

c. Conclusions

The inspectors concluded that the safety consequence of the ten unit heater breakers being open on 1NBG was minimal. The inspectors identified a violation associated with a lack of control of heater breakers on MCC 1NBG.

O3 Operations Procedures and Documentation

O3.1 Walkdown of Clearances (71707)

During the inspection period, the inspectors walked down the following clearances:

19602885	Diesel generator 1A end-of-cycle maintenance
19715002	Reserve auxiliary transformer 1NXRB (RAT-1B)
19715101	1R7 Reactor Coolant Pump (RCP) #1 (electrical only)
19715104	1R7 RCP #4 (electrical only)
19715106	Reactor coolant system drain down
19715111	RCP # 1 seal injection
19715121	Auxiliary Component Cooling Water isolation and drain to all RCPs
19715181	Seal injection loops 1, 2, and 4 valve work
19715810	Main feedwater pump turbine B vapor extractor
19715899	Containment building cavity cool unit fan #2
19716029	1R7 air pressure test for 6A and 5A feedwater heaters
19716030	Isolation of shell side of 6B and 5B feedwater heaters
19716104	Chemical volume and control, reactor coolant system isolation valve

b. Observations and Findings

The inspectors did not identify any significant problems or concerns during these walkdowns. Minor issues were provided to the licensee for resolution. During the installation of clearance 19715002 a reactor operator identified that the clearance included the removal of an incorrect control power breaker from service. The clearance error was corrected. The inspectors concluded that this was an example of good attention to detail on the part of the operator.

O3.2 Procedure Review Process (71707)

a. Inspection Scope

The inspectors reviewed the circumstances surrounding several recent procedural problems. The procedures described below were recently revised. Each revision resulted in unexpected plant condition that had an unexpected response. Summarized below are event details related to the procedural revision errors.

b. Observations and Findings

Procedure 14810-1, "Turbine Driven Auxiliary Feedwater (TDAFW) Pump and Check Valve Inservice Test (IST) Response Time Test," Rev. 23, was performed on August 4, 1997. The performance of Rev. 23 resulted in the introduction of auxiliary feedwater into all four steam generators. This issue was previously documented in Inspection Report 50-424, 425/97-09. It was determined during the previous review of the event that when step 5.2.5 of procedure 14810-1 was performed, an open signal was received at all four of the TDAFW motor operated discharge flow control valves. Because the TDAFW pump was operating at that time, Auxiliary Feedwater (AFW) was fed to all four steam generators. The licensee revised Procedure 14810-1 on May 30, 1997, to delete a step that manually closed the TDAFW discharge isolation valve, 1-1302-U4-015. Procedure 14810-1 was revised to comply with an NRC commitment to maintain that valve open at full power operation. The procedure revision review performed by operations management did not recognize that the deletion of the step to close the manual valve would result in AFW injection into the steam generators.

Procedure 14667-1, "Train B Diesel Generator and Emergency Safety Features Actuation System (ESFAS) Test," Rev. 5, Section 5.2, "Loss of Off Site Power Concurrent with Safety Injection (SI)," was performed on October 8, 1997. When the SI signal was initiated, with the power supply to the 4160 1E electrical bus isolated, the diesel generator did not start. Operations personnel restored power to the 4160 bus per abnormal operations procedure 18031-C, "Loss of Class 1E Elect System," Rev. 15. During the event review, it was determined that the Rev. 5 procedure changes added steps intended to allow testing of the diesel generator start signal from SI actuation. However, the revised procedure steps resulted in the isolation of the control air from the DG auto-start circuit, thereby preventing the diesel generator from starting. During the procedure review and approval process it was not recognized that control air would be isolated during performance of this ESFAS test. The safety significance of this event was minimal since Unit 1 was defueled at the time.

On October 18, while performing Procedure 12002-C, "Unit Heatup To Normal Operating Temperature and Pressure," Rev. 34, the SI system was made inoperable due to opening SI discharge valves to the hot legs;

1HV-8802A and 1HV-8802B. The plant was in Mode 3 when it was discovered that the valves were mis-positioned. Operations personnel performed checklist 3 of Procedure 12002-C which was intended to aligned the SI system to operable status. However, the valve positions for 1HV-8802A and 1HV-8802B were erroneously listed as "OPEN" rather than "CLOSED". As a result, the misalignments made the safety injection system inoperable. Approximately 1-½ hours later, operations personnel identified the misalignment and immediately closed the valves. After the valves were discovered to be mis-positioned, operations personnel reviewed the TS and determined that Unit 1 was within the four hour grace period allowed in Note 2 of TS 3.5.2, Emergency Core Cooling System (ECCS)-Operating. However, after reviewing the plant conditions, the inspectors determined that TS 3.5.2, Limiting Condition for Operation (LCO) Action Statement "A" had been entered since the second part of TS 3.5.2 Note 2 stated that two trains of ECCS must be operable prior to exceeding 375° F in all four RCS cold legs. Based on a review of RCS cold leg temperatures, after entry into Mode 3, the licensee operated above the 375° F limit with for approximately 1-½ hours. However, the safety significance of the issue was minimal due to the licensee meeting the LCO Action Statement "A" completion time well within the required 72 hours.

The inspectors determined that Procedure 00051-C, "Procedures Review and Approval," Rev. 24, required review of the revised procedures by qualified personnel which may include review by the Plant Review Board. The inspectors verified that the procedure revision packages indicated that the appropriate reviews were performed where necessary. However, the reviews performed on these revised procedures did not effectively identify the errors prior to use of the procedures.

c. Conclusions

The inspectors concluded that each event discussed above resulted from errors introduced during the revision process. The errors and discrepancies identified were not recognized during the review and approval process. The inspectors identified a weakness in the review and approval process for revisions to procedures. The inspectors also concluded that the failure of the operations crew to recognize the entry into the applicable LCO Action Statement for an inoperable ECCS System was a weakness.

O8 Miscellaneous Operations Issues (92901)

O8.1 Personnel Outage Work Time

a. Inspection Scope (71707)

The inspectors reviewed a random sample of time sheets and overtime records of plant staff and contractors during 1R7. The inspection was conducted for plant staff that performed safety-related functions to verify compliance with TS 5.2.2.e., Unit Staff, and to review the overtime authorization process. The inspectors reviewed licensee documentation including personnel payroll time sheets, personnel on-site time as determined by security computerized personnel tracking logs, and Procedure 00005-C, "Overtime Authorization," Rev. 8.

b. Observations and Findings

The inspectors reviewed time sheets for personnel in operations, electrical and mechanical maintenance, health physics (HP)/chemistry, and instrumentation and control (I&C) departments. In addition, the inspectors reviewed various contractor employee time sheets.

The inspector noted, during the review, that deviations from TS 5.2.2.e guidelines were approved in accordance with procedure 00005-C. The inspector verified that Procedure 00005-C included controls to limit working hours as required by TS 5.2.2.e. However, the inspectors noted that excess overtime authorization forms were not readily available for review for all personnel. The review indicated that approximately 10% of operations personnel and approximately 50% of maintenance personnel did not have "signed" overtime authorization sheets. Based on discussions with licensee management overtime was "verbally" approved, but the time was not documented properly. Verbal approval was permitted in accordance with 00005-C. The missing time sheets identified were in the process of being generated during the inspectors review.

The inspectors also noted, as a result of this review, that overtime authorized for 1R7 increased over that authorized for previous outages. The licensee indicated that the increased time was a result of a longer outage (approximately 45 days) and less available resources. However, the inspectors determined that the overtime for safety related work authorized by plant management met the requirements of TS 5.2.2.e. The overtime was used during an extended period of shutdown for refueling.

c. Conclusions

The inspectors concluded that the licensee was in compliance with TS requirements for plant staff hours. In addition, the inspectors noted that deviations from TS 5.2.2.e requirements were approved in accordance with procedure 00005-C. Based on the inspectors' review, no abuse of overtime was identified.

08.2 (Closed) VIO 50-424/97-04-01: Containment Debris Identified During Unit 1 Planned Outage (1P1)

(Closed) VIO 50-425/96-11-02: Inadequately Performed Surveillance to Closeout Unit 2 Containment

a. Inspection Scope (71707)

As a result of previous issues identified with containment closeout, the inspectors conducted a containment exit inspection October 18, 1997. As part of this inspection, the inspectors reviewed Procedures 14900-C, "Containment Exit Inspection," Rev. 3; and 14903-1, "Containment Emergency Sump Inspection," Rev. 7, the Deficiency Card (DC) documenting debris identified, and the subsequent engineering evaluation to assess the impact on sump performance.

b. Observations and Findings

On October 18, 1997, the inspectors conducted an inspection of Unit 1 containment to assess material condition prior to startup. At the time of the inspectors' entry into containment, the licensee had completed their preparation of containment and were in Mode 4.

In general, the material condition within containment was much improved from previous inspections (reference Inspection Reports 50-424, 425/97-04 and 50-424, 425/96-11). However, the inspectors identified two noteworthy items inside containment, in addition to pieces of debris within readily accessible areas of containment. A respirator, in a sealed bag, and a fire extinguisher were identified on the 220 foot elevation of containment. The miscellaneous debris identified was randomly distributed throughout various levels of containment. The inspectors also identified several minor material deficiencies for licensee resolution.

An engineering evaluation estimated the total amount of debris and miscellaneous materials removed by the inspectors at approximately two square feet. Based on results of the licensee's engineering analysis of the material, containment sump performance was not impacted or rendered degraded. In addition, the items identified were not of sufficient quantity to significantly affect the post accident water chemistry, fire protection analysis, flooding analysis, peak clad temperature analysis, containment pressure/temperature analysis, or the hydrogen generation analysis. This conclusion appears reasonable based on the nature and amount of material.

c. Conclusions

The inspectors concluded that while the items identified did not represent a substantial challenge to containment sump performance, the loose debris should have been resolved as a result of the licensee's closeout of containment. Overall, the inspectors concluded that the licensee's implementation of a new program to clean containment prior to the performance of a closeout exit inspection has adequately addressed previously identified loose debris issues. The increased emphasis that the licensee placed on material control within containment during 1R7 achieved successful results.

O8.3 (Closed) Inspection Follow-Up Item (IFI) 50-424, 425/97-08-01: Resolution of Self-Assessment Findings

This IFI concerned disposition of comments and recommendations resulting from an Independent Safety Engineering Group (ISEG) review and a self-assessment of the Plant Modification and Maintenance Support (PMMS) organization. The ISEG comments were provided only as a feedback and did not require a response. However, the ISEG organization clarified its guidance to state that a specific response request and due date will be included whenever a response is expected. The PMMS self-assessment comments were routed to the responsible organization for response.

Based on this review the inspectors concluded that the licensee has adequately addressed this issue. This IFI is closed.

O8.4 (Closed) LER 50-424/97-006, Hydrogen Monitoring System Train Rendered Inoperable

This issue was determined to be of minor safety significance. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Work Order Observations

a. Inspection Scope (62707)

The inspectors observed portions of maintenance activities involving the following work orders:

A9700877	Control room door seals replaced
19601736	Diesel generator air start receiver relief valve
19602190	Replace reactor coolant pump number 3 internals
19602931	Core reload
19602941	Reactor head lift and reassembly
19602952	Tension reactor head studs
19602954	Assemble conoseals
19700123	Remove/Replace pressurizer safety valve snubbers
19700541	Replace snubber 11201030H60 on reactor coolant system
19700857	Support pin lower guide tube replacement

19701932	Cavity cooler coil replacement (DCP VAN0021)
19702923	Investigate and repair indication on 1HS-7144
19702935	Diesel generator train B jacket water leaks
19702996	Hydrostatic test and reactor coolant pump seal installation
19703240	Control rod M-2 trouble shooting
29702539	Containment condensate cooler leak detection

b. Observations and Findings

The observed maintenance activities were generally completed thoroughly and professionally.

M1.2 Surveillance Observation

a. Inspection Scope (61726)

The inspectors observed the performance or reviewed the following surveillances and plant procedures:

14005-2	Shutdown Margin Calculations, Revision (Rev.) 11
14240-1	Manual Steamline Isolation TADOT (Trip Actuation Device Operability Test), Rev. 2
14406-2	Boron Injection Flow Path Verification - Shutdown, Rev. 7
14546-1	Turbine Driven Auxiliary Feedwater Pump Operability Test, Rev. 7
14710-1	Remote Shutdown Panel Transfer Switch and Control Circuit 18-month Surveillance Test (1AA02), Rev. 20
14727-C	Load Tests for Refueling Machine and Auxiliary Hoist, Rev. 3
14748-1	Auxiliary Feedwater Pump and Check Valve Cold Shutdown Inservice Test and Turbine Driven Auxiliary Feedwater Pump Auto Start Test, Rev. 16
14750-1	DRPI (Digital Rod Position Indication) 18-month Operability Test, Rev. 5
14786-C	Turbine Driven Auxiliary Feedwater Pump Overspeed Test, Rev. 6
14808-1	Centrifugal Charging Pump Train B and Check Valve IST (Inservice Test) and Response Time Test, Rev. 21
14809-2	ESF (Emergency Safety Feature) Chilled Water Pump Inservice Test, Rev. 9
14825-1	Quarterly Inservice Valve Test, Rev. 40
14850-1	Cold Shutdown Valve Inservice Test, Rev. 28
24769-1	Accumulator Tank #2 Level 1L-953 Channel Calibration, Rev. 14
24807-1	Refueling Water Storage Tank Level 1L-991 Analog Channel Operational Test, Rev. 13
27147-C	Reactor Coolant Pump Seal Cartridge Static Test, Rev. 1
54015-C	Reactor Coolant System RTD (Resistant Temperature Detector) Cross-Calibration, Rev. 6
56003-1	DP (Differential Pressure) Test for 1-HV-1831, Rev. 1
88006-C	Rod Drop Time Measurement (Cold) Test, Rev. 7

T-ENG-97-12 Control Rod Drop Testing, Rev. 1
T-ENG-97-27 Ten (10) Year Class 1 Pressure Test, Rev. 0
T-ENG-97-28 Centrifugal Charging Pump 1A Performance Test in Mode 5, Rev. 0

b. Observations and Findings

The observed surveillance activities were generally completed thoroughly and professionally.

Performance of surveillance Procedure 14809-2, "ESF Chilled Water Pump Inservice Test," Rev. 9, was observed by the inspectors. During the surveillance, the initial indicated ESF Chiller #2 flow was below the flow range required by the procedure. Procedure step 5.2.6.4 directed the completion of section 5.3 in order to obtain the appropriate flow rate. Guidance of step 5.2.6.4 indicated that section 5.3 was to be completed in its entirety. Section 5.3 did not allow for the adjustment of the flow rate and then a return to section 5.2. The last step of section 5.3 directed the reactor operator to return the chill water thermostat temperature to the original setting which caused the flow rate to be returned to its original value. This "circle" between sections 5.2 and 5.3 would not allow proper flow rate to be established. After it was recognized that the procedure could not be performed as written the reactor operator backed out of the procedure. After a discussion with the Unit Shift Supervisor, a temporary procedure change was completed and the surveillance was performed without incident.

M1.3 Inservice Inspection

a. Inspection Scope (73753)

To evaluate the licensee's inservice inspection (ISI) program and the program's implementation, the inspectors reviewed selected records, procedures and observed work in progress. Observations were compared with applicable procedures, the Updated Final Safety Analysis Report (UFSAR), and American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code Sections V and XI, 1989 Edition, No Addenda (89NA).

Specific areas examined included the following observation: magnetic particle (MT) examinations of Item Nos. 11201-V6-001-W02 and 11301-001-13; liquid penetrant (PT) examination of Item No. 11204-001-9; manual ultrasonic (UT) examination of Item Nos. 11301-001-1, 11301-001-2, 11301-001-3, 11301-001-9, and 11301-001-10; data acquisition activities associated with eddy current (ET) examinations of steam generator (S/G) tubing; and direct visual (VT) examination of support Nos. 11205-005-H013, 11205-007-H032, 11205-007-H033, 11205-007-H041, and 11208-411-H017. Review of selected completed examination reports; and review of the Repair and Replacement Program.

Procedures reviewed included: UT-V-404, "Manual and/or Mechanized Ultrasonic Examination of Full Penetration Welds," Revision 9; MT-V-505, "Magnetic Particle Examination," Revision 4; PT-V-605, "Liquid Penetrant Examination Procedure," Revision 3; and VT-V-735, "Visual Examination (VT-3)," Rev. 3.

The inspectors performed an independent evaluation of indications to confirm the licensee's ISI examiners' evaluations.

The inspectors reviewed records for the nondestructive examination (NDE) personnel and equipment utilized to perform ISI examinations. The records included: NDE equipment calibration and materials certification; and records attesting to NDE examiner qualification, certification, and visual acuity.

b. Observations and Findings

The inspectors noted during the contractor-performed MT examination of weld No.11301-001-13, that the contractor examiner removed excess particles from the examination area of interest during the examination by an oral airstream. This was contrary to procedure MT-V-505, "Magnetic Particle Examination," Rev. 4, paragraph 10.7.1, which required excess particles to be removed by a gentle airstream from an aspirator bulb. The concern was two-fold: the force of an oral airstream is not well controlled; and the possibility of introducing sputum into the examination area of interest could interfere with the examination. The licensee subsequently reviewed all MT examinations performed by the above examiner and reexamined the weld. The inspectors considered that the licensee took appropriate actions to determine the extent of the problem, correct the problem and prevent recurrence. The licensee documented this issue in DC 1-79-562. In addition, the inspectors noted that this failure constituted a violation of minor safety significance and consistent with Section IV of the NRC Enforcement Policy this was identified as Non-Cited Violation (NCV) 50-424/97-10-02, Failure of Contractor Examiner to Follow MT Procedure.

Except as noted above, ISI examinations observed/reviewed were conducted in accordance with approved procedures, by qualified and certified examiners using certified/calibrated equipment and materials.

The licensee had implemented the containment inspection rule Repair and Replacement (R/R) Program by issuance of GEN-25, Section 3.1, "Repair/Replacement of ASME Code Class 1, 2, 3, and MC Components," and Section 3.2, "Repair/Replacement of ASME Code Class CC Components," dated September 8, 1997, and September 7, 1997, respectively.

Relative to Section 3.1, the inspectors noted that the repair of arc strikes was excluded from GEN-25 without regard to size or severity. The licensee informed the inspectors that their program placed no requirements on the repair of arc strikes. This was of concern because arc strikes can harbor minute cracks, porosity, hard zones and chemical heterogeneity. Despite their small scale, these conditions can trigger a major failure when they are located in an important stress field. The inspectors discussed this issue with the licensee, who indicated that they would look further in this matter and take appropriate action.

c. Conclusions

Except for the NCV related to failure to follow the MT procedure ISI activities observed/reviewed were conducted in accordance with procedures, licensee commitments and regulatory requirements. The licensee's programmatic coverage of arc strikes was considered a weakness.

M1.4 Steam Generator (S/G) Tubesheet Rework

a. Inspection Scope (73753)

On May 28, 1996, the Vogtle Unit 1 digital metal impact monitoring system (DMIMS) detected loose parts in S/G #4. Within approximately 15 hours, the DMIMS indications were confirmed as loose parts. An object was located and removed from the channel head. A second object was lodged in the tube end at location Row 1 Column 115. Subsequent evaluation indicated the foreign objects to be from a guide tube support pin. The parts removed from S/G #4 were the support pin nut and locking device disk. A fragment of the support pin nut was removed from the cold leg. Remote visual examination confirmed that of the 5330 tubes, 3612 had from moderate local damage to heavy deformation of all tube end surfaces.

The procedures reviewed included: "Vogtle-1 Steam Generator (SG) #4 Engineering Evaluation of Tube-To-Tubesheet Weld Region," dated March 1997; GP-16632, "Tube-to-Tube Weld Repair Engineering Evaluation," dated June 10, 1997; GP-16636, SG 1-4 Tube Bundle Integrity Assessment SECL," dated June 18,1997; and STD-FP-1997-8050, "Tube Entry Rework in Model F Steam Generator Tubes at Vogtle Units 1 and 2," Rev. 2.

b. Observations and Findings

Engineering evaluation indicated that the primary to secondary leaks were adequately prevented by the hydraulic expansion of the tubes into the tubesheet. The inspectors determined that the engineering evaluation was sound and comprehensive. Therefore, all that was required to address the damaged tube end seal weld was to "rework" the tube ends by hard rolling, thereby assuring the subsequent passage of eddy current probes. The licensee was in the process of hard rolling the 3612 tubes with moderate local damage to heavy deformation of all tube end surfaces. To evaluate the licensee's activities related to the damage to the hot leg S/G #4 tubesheet, the inspectors interviewed licensee and contractor personnel, reviewed procedures and selected quality records, and observed work and work activities. Observations were compared with applicable procedures and the UFSAR. The procedure was of good quality and personnel were appropriately trained and qualified.

c. Conclusions

Unit 1 S/G #4 tubesheet rework activities were supported by appropriate evaluations, controlled by well written procedures, and highly trained and motivated individuals.

M1.5 Guide Tube Support Pin (Split Pin) Replacement

a. Inspection Scope (73753)

As a result of the May 28, 1996 DMIMS detection of loose parts in Unit 1 SG #4, and their subsequent identification, the licensee elected to replace all the Unit 1 guide tube support pins (Inconel 750) with cold worked type 316 stainless steel pins. To evaluate the licensee's activities related to the guide tube support pin replacement, the inspectors interviewed licensee and contractor personnel, reviewed procedures and selected quality records, and observed work and work activities.

The procedures reviewed included: DR No.9701, "Cold Worked 316 Stainless Steel Replacement Guide Tube Support Pin," dated June 26, 1997, and EN 2.7.1 GAE/GBE-1, "Guide Tube Support Pin Replacement at Vogtle Electric Generating Plant Units 1 and 2," Rev. 1.

b. Observations and Findings

Specific activities observed included: cap screw untorquing; cap screw unscrewing; cap screw removal; guide stud installation; split pin removal; and lower guide tube installation. Work activities were accomplished consistent with the procedure, monitored and controlled. Observations were compared with applicable procedures and the UFSAR. The procedure was well written and of good quality.

c. Conclusions

Unit 1 split pin replacement activities were supported by appropriate evaluations, controlled by well written procedures, and highly trained and motivated individuals.

M1.6 Troubleshooting Program Review (61726)

a. Inspection Scope

As a result of previously identified issues with the lack of a formal troubleshoot program, the licensee developed Procedure 10024-C.

"Equipment Troubleshooting," Rev. 0, to facilitate troubleshooting efforts. During Unit 1 startup, the inspectors observed two troubleshooting activities which utilized Procedure 10024-C. The inspectors also reviewed the associated paperwork

b. Observations and Findings

During the performance of Procedure 14666-1, "Train A Diesel Generator and ESFAS Test," Rev. 5, slave relay K325 failed to energize. The failure of slave relay K325 prevented the piping penetration filtration system from starting as designed. Using the troubleshooting techniques specified in Procedure 10024-C, slave relay K325 was removed and bench tested. No problems with slave relay K325 were identified during the bench test. Slave relay K325 was then placed back in service and monitored during the second performance of surveillance 14666-1. During performance of the second test, the relay operated correctly.

The inspectors observed a second troubleshooting effort during the performance of hot rod drop tests. The DRPI for control rod M-2 malfunctioned which resulted in a manual reactor trip (reference Section O1.4). Using Procedure 10024-C, detailed directions were developed to determine that the indication malfunction was actually caused by the known failure of the data "B" coil. Control rod M-2 was successfully withdrawn after placing the DRPI system in data "A" only.

c. Conclusions

The inspectors concluded that, during the troubleshooting activities, appropriate personnel from reactor engineering, operations, and maintenance departments were involved. Work orders and temporary procedures were developed as needed and in a timely manner. The inspectors also concluded that the troubleshooting activities were performed in accordance with procedure 10024-C, "Equipment Troubleshooting," Rev. 0.

M3 Maintenance Procedures and Documentation

M3.1 Diesel Generator and ESFAS Testing (61726)

a. Inspection Scope

The inspectors observed performance of Diesel Generator and ESFAS testing as part of the safety-related surveillance startup testing. This surveillance is conducted on a 18 month frequency. The procedures, acceptance criteria, briefing techniques and communications were reviewed or observed by the inspectors.

b. Observations and Findings

The inspectors observed performance of Procedure 14666-1, "Train A Diesel Generator and ESFAS Test," Revision 5, Section 5.2, "Loss-Of-Offsite-Power (LOSP) In Conjunction With An ESF Actuation Test Signal Followed By SI Actuation With The DG In A Test Mode;" Section 5.3, "DG Start on LOSP;" and Section 5.4, "DG Start on SI Signal." The inspectors reviewed results documented in the completed procedure and verified that test results met the acceptance criteria of each respective section. The inspector also reviewed the failed component/test exception logs for both the A and B train ESFAS test and verified that test exceptions were retested or dispositioned properly.

On October 8, Diesel Generator 1B failed to start during the performance of surveillance 14667-1, "Train B DG and ESFAS Test," Section 5.2. The licensee determined that the failure was due to revised procedural steps which resulted in the isolation of the control air from the DG auto-start circuit, thereby preventing the diesel generator from starting. (Refer to Section O3.2.) The failure of DG 1B to start resulted in the 4160 KV 1E essential electrical switchgear, 1BA03, remaining de-energized. Operations shift personnel responded by re-energizing 1BA03 per abnormal operating procedure (AOP) 18031-C, "Loss of Class 1E Elect Sys," Rev. 15. Operations personnel performance of the AOP was efficient and affective.

c. Conclusions

The inspectors concluded that DG and ESFAS tests were performed in accordance with written procedures. The inspectors identified several minor administrative issues that were forwarded to the licensee and appropriately dispositioned. Overall, the test activities observed were well controlled.

M3.2 Emergency Core Cooling System Flow Test (61726)

a. ECCS Subsystem Flow Balance

The inspectors observed portions of the performance of Surveillance 14721-1, "ECCS Subsystem Flow Balance and Check Valve Refueling Inservice Test," Rev. 18. The test verified flow rates of each emergency core cooling system. The surveillance is performed on an 18-month frequency or at the completion of ECCS modifications.

b. Observation and Findings

Prior to 1R7 the licensee revised Procedure 14721-1 which altered the test methodology and ultimately the acceptance criteria. Procedure 14721-1, Revision 18, acceptance criteria was modified from a measured flow-based test to a calculated resistance-based methodology. A review of a licensee performed safety evaluation indicated that the change to a resistance-based acceptance criteria results in a less restrictive flow band. However, the new methodology was maintained consistent the UFSAR accident analysis to ensure adequate flow rates are achieved for each ECCS system. The new calculated resistant-based method used measured differential pressure of the system to calculate a system resistance. That resistance, which reflected system and pump performance, was used to calculate flow and determine system operability.

The inspectors observed the performance of Procedure 14721-2, Sections 5.1, 5.2, 5.4, and 5.5. These tests included a Centrifugal Charging Pump (CCP) cold leg injection; Safety Injection cold leg injection; Residual Heat Removal (RHR) cold leg injection; and RHR check valve test. The surveillance was performed successfully with the exception of section 5.1 which involved an issue with the test setup for CCP train "A". The licensee determined after completion of section 5.1 that the measured discharge pressure for CCP train "A" was recorded from instrumentation that was incorrectl, located. The test setup did not reflect the proper configuration consistent with the new resistance-based program. After installation of additional instrumentation, CCP train "A" was tested and data collected indicated that the pump successfully met established performance criteria of the 14721-1 surveillance.

c. Conclusions

The inspectors did not identify any concerns with the new test methodology for the ECCS flow balance surveillance. Based on this review, the inspectors concluded that the test was performed in accordance with written procedures, was well controlled, and coordinated.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Unresolved Item (URI) 50-424, 425/95-27-03: Proper Calibration of Reactor Trip System and ESFAS Trip Setpoints

a. Inspection Scope (92902)

The inspectors previously opened URI 50-424, 425/95-27-03, Proper Calibration of Reactor Trip System and ESFAS Trip Setpoints, to document an issue concerning the licensee's adherence to inequality symbols stated in the TS Reactor Trip System (RTS) and ESFAS instrumentation tables. The issue was opened pending NRC's review of the licensee's methodology. Based on NRR's conclusion with respect to the use of inequality symbols, the inspectors discussed the NRC's position on trip setpoints with I&C personnel and licensee maintenance department management.

b. Observations and Findings

The inspectors identified a concern with the adherence to inequality symbols (i.e., greater than or equal to (≥), and less than or equal to (≤)) associated with TS tables trip setpoints. Specifically, the inspectors identified that the licensee's calibration procedures did not strictly adhere to the symbols as stated in TS RTS and ESFAS tables 3.3.1-1, "Reactor Trip System Instrumentation," and 3.3.2-1, "Engineered Safety Feature Actuation System Instrumentation." The concern was identified that, based on the licensee's calibration procedures, it was possible to calibrate an instrument and have its "as-left" setpoint be outside the TS inequality values annotated in the TS tables.

Based on the inspectors' review, it was determined that the Vogtle calibration procedures did not, in fact, establish calibration procedures heeding the inequality symbols. The licensee provided documentation that stated that the Westinghouse setpoint methodology and Vogtle TS Bases documents established trip setpoint values as "nominal" values. Therefore, the Vogtle calibration procedures were maintained consistent with those documents. However, the inspectors' review of TS indicated that trip setpoints had minimum or maximum values (inequalities) for each function, rather than trip setpoint "nominal" values.

The inspectors reviewed "as-left" calibration data sheets which indicated that the licensee did not take advantage of procedure tolerances, as such, no instrument trip setpoints were found to be beyond the TS "allowed values." In accordance with the TS Bases document guidance, a measured setpoint which does not exceed the "allowed value," is considered operable. Therefore, because no instrument trip setpoint was left outside the "allowed value" this issue had minimal safety significance.

However, a review of the I&C calibration procedures identified that approximately 83 procedures per unit would potentially set instruments outside the trip setpoint inequality values. Of the "as-left" calibration data sheets reviewed by the licensee, approximately 30% were identified that did set instrument trip setpoints beyond the minimum or maximum values indicated in the TS tables. Based on review by the inspectors of those data sheets, the inspectors verified that not all instruments calibrated during the Unit 1 refueling outage were in accordance with the TS tables trip setpoints and the associated inequality symbols. As a result, the licensee established administrative controls to limit the resetting of trip setpoints consistent with the TS inequality values delineated in the TS RTS and ESFAS instrumentation setpoints tables. Procedure 20028-C, "RTS and ESFAS Instrumentation Trip Setpoint Control," Rev. 2, was developed and implemented for plant personnel use on October 6, 1997.

c. Conclusions

The calibration procedures identified that set the "as-left" instrument trip setpoints beyond the inequality values are contrary to TS RTS and ESFAS tables 3.3.1-1 and 3.3.2-1 values. However, consistent with Section IV of the NRC Enforcement Policy, this was identified as NCV 50-424, 425/97-10-03, Improperly Set RTS and ESFAS Trip Setpoints.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Valve Modifications to Eliminate Pressure Locking and Thermal Binding

a. Inspection Scope (37551)

The inspectors reviewed licensee actions taken in response to NRC Generic Letter (GL) 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." That review was documented in Inspection Report 50-424, 425/96-02. However, as part of that review, the inspectors evaluated a recent design change package (DCP) implemented during the Unit 1 seventh refueling outage. This modification was implemented on the remaining Unit 1 valves determined by the licensee to be affected. The inspectors conducted field observation of a portion of the modification to 1-HV-8840, Residual Heat Removal (RHR) hot leg injection crossover isolation valve, and a post-maintenance review of the completed work order.

b. Observations and Findings

The licensee's evaluation in response to GL 95-07 identified eight valves, including 1-HV-8840, in each unit for modification to provide additional assurances that the valves will be capable of performing their design basis function. The inspectors reviewed DCP 97-V1N0022, "RHR Hot Leg Injection Crossover Valve Pressure Locking Prevention," which modified this valve. This modification consisted of drilling a 1/8-inch hole through the down stream side of the valve disc thus providing a vent path for any pressure trapped in the valve bonnet. Drilling a small hole in the disc of the valve provided a relief path to prevent the build-up of pressure in the bonnet area, thereby precluding the possibility of pressure locking for this valve.

The inspectors reviewed DCP 97-V1N0022 in depth. As part of this review, the inspectors reviewed the TS; applicable portions of Updated Final Safety Analysis Report (UFSAR) Sections 5.4.7, 6.2.2, 6.3, and 15; and the licensee's response to GL 95-07 dated February 8, 1996. The inspectors also reviewed the 10 CFR 50.59 safety evaluation for the DCP and verified that the safety evaluation considered items such as the impact on leakage, Inservice Inspection/Inservice Test (ISI/IST) program, leak rate testing, seismic and environmental qualification, and valve seating. The inspectors concluded that DCP 97-V1N0022 was prepared in accordance with applicable licensee procedures. The 10 CFR 50.59 safety evaluation provided the technical basis that there was no unreviewed safety question associated with this DCP.

c. Conclusions

The inspectors concluded that the DCP package was complete and sufficiently detailed, and implementation of the valve modification was satisfactory.

E3 Engineering Procedures and Documentation

E3.1 APEX User Manual Review

a. Inspection Scope (92903)

As documented in Inspection Report 50-424, 425/96-11, the licensee experienced difficulties in performing an Estimated Critical Position (ECP) using the APEX computer code for a core with less than ten days burnup history available. To provide more explicit guidance, the licensee proposed changes to the APEX users manual to include: additional guidance on calculations for low burnup cores; determining average control rod position and average power during periods of zero power operation; the number of significant digits and when zero can and cannot be used; and determining proper time periods and burnup for core depletion history, reference point, and shutdown time for input into APEX. These corrective actions were considered as mitigating factors in identifying this issue as NCV 50-425/96-11-04, Inaccurate Calculation of Estimated Critical Condition. The inspectors reviewed Rev. 4 of the APEX users manual to determine the effectiveness of the corrective actions and if the corrective actions fully addressed the deficient conditions identified. The inspectors also interviewed qualified reactor engineers to ascertain the usefulness of the revised manual if a reactor trip occurred with less than 10 days burnup history. This review was performed prior to startup of Unit 1 from the seventh refueling outage.

b. Observations and Findings

Based on the review of Rev. 4 of the APEX users manual, the inspectors determined that the Licensee's corrective actions were not adequate in that the APEX users manual was not revised to include all the identified corrective actions. In addition, training that the licensee conducted on the use of APEX code provided additional guidance that was not described in the APEX users manual, and in some cases, contradicted guidance included in Rev. 4 of the APEX users manual. Specifically, the inspectors identified that the APEX users manual permitted zero to be used as an input value for reactor power, but the training indicated that zero could not be used for conditions with less than ten days burnup history or incorrect results would be obtained. Instead, the training indicated that a "small number" would have to be substituted. The APEX users manual cautioned that entering small positive values may result in negative burnup values producing incorrect results. The APEX computer code did not provide an error check for negative burnup values and provided no guidance on what constituted a "small number." Additionally, during a demonstration of APEX by a qualified reactor engineer, the inspectors observed that the reactor engineer had to rely on training handouts in order to obtain accurate results.

c. Conclusions

The inspectors determined that the APEX manual had not been sufficiently clarified to include additional guidance necessary to ensure an accurate ECP can be determined after a reactor trip for a core with less than ten days burnup history. The licensee failed to incorporate adequate corrective actions in Rev. 4 of the APEX users manual prior to the restart of Unit 1. This is a violation of 10 CFR 50 Appendix B Criterion XVI and is identified as VIO 50-424/97-10-04, Failure to Take Adequate Corrective Actions to Revise the APEX Users Manual.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) LER 50-424/96-005, Rev. 1: Unqualified Cabling Used in Containment Sump Level Transmitters

a. Inspection Scope (92902)

The inspectors reviewed LER 50-424/96-005, Rev. 1, Unqualified Cabling Used in Containment Sump Level Transmitters, associated Maintenance Work Orders (MWOs), Deficiency Cards (DCs), site drawings, and plant procedures. Those items reviewed are listed below:

- Procedure 00057-C, "Event Investigation," Rev. 10
- Procedure 00058-C, "Root Cause Determination," Rev. 11
- Procedure 81030-C, "Preparation and Processing of Draft Licensee Event Reports and Technical Specification Reports," Rev. 2
- AX3D-AA-A00V-01, "General Notes, Installation Instructions, and References for Cable Splices," Rev. 2
- AX3D-AA-A00V-02, "Notes and Details for In-Line Cable Splices," Rev. 3
- AX3D-AA-A00V-03, "Notes and Details for In-Line Bolted Cable Splices," Rev. 2
- AX3D-AA-A00V-04, "Three-Way, Four-Way & V Cable Splices Details," Rev. 2

b. Observations and Findings

The inspectors reviewed LER 50-424/96-005, Rev. 1, including the corrective actions developed. The licensee was unable to determine a root cause of the event due to a lack of documentation available of the maintenance and the length of time since the maintenance was accomplished during construction of Unit 1. It was determined that these instruments do not perform an active function in mitigating the consequences of an accident, and that other instrumentation was available to determine containment water level. Actions to address the LER corrective actions were completed and properly documented. Training adequately addressed the issue. However, the licensee's review was limited in scope.

A "broadness review," as defined in Vogtle Electric Generating Plant (VEGP) Procedure 00058-C, is "A review... to determine if this type of occurrence could impact other trains, channels, components, or similar processes on either unit..." The broadness review for LER 50-424/96-005 concentrated on the containment sump level transmitters and, therefore, only these splices were inspected. In this LER there were two identified problems. The first was that the sump level transmitter splices were not environmentally qualified because the outside jacketing had been removed. Secondly, unjacketed splices were installed in environmentally unqualified junction boxes. Since the broadness review concentrated on the affected components it failed to identify the improper installation and repair of Eaton cable splices in other applications. Consequently, the full scope of unqualified splices used in the plant was not identified. Additionally, the review did not identify a similar issue which occurred during construction. It was not until additional examples of unqualified splices were discovered that the licensee expanded the scope of their corrective actions (see LER 50-424/97-004, "Unqualified Cables Renders Atmospheric Relief Valves Inoperable.")

Based on this broadness review, the licensee looked more at components than processes (i.e., looked at other sump level transmitters for faulty splices rather than sample different component splices). Licensee personnel stated that focusing the review was done in an effort to ensure a manageable sample size and appropriately apply resources.

c. Conclusions

The corrective actions committed to in LER 50-424/96-005 have been completed. The inspectors determined that the review conducted for LER 50-424/96-005 was of limited scope and did not identify that the Eaton cable splicing issue extended beyond the containment sump level transmitters. However, the broader implications were recognized and addressed in LER 50-424/97-004, Unqualified Cables Renders Atmospheric Relief Valves Inoperable. LER 50-424/96-005 is closed.

E8.2 <u>(Closed) LER 50-424/97-004:</u> Unqualified Cables Renders Atmospheric Relief Valves Inoperable

a. <u>Inspection Scope (92902)</u>

The inspectors reviewed LER 50-424/97-004, Unqualified Cables Renders Atmospheric Relief Valves Inoperable, associated MWOs, DCs, site drawings, and plant procedures. Those items reviewed are listed below:

- Procedure 25718-C, "Heat Shrink Insulation for Control and Power Cable Splices and Terminations," Rev. 17
- Procedure 85016-C, "Quality Control Monitoring," Rev. 6
- Specification X3AR01-E9, "Cable Wiring Installation and Connections," Rev. 32
- AX3D-AA-A00V-05, "Grey-Body Cable Splices," Rev. 3
- AX3D-AA-A00V-06, "Transition Cable Splices," Rev. 2
- AX3D-AA-A00V-07, "Transition Cable Splices," Rev. 3
- AX6D042, "Instruments Requiring Qualification for Harsh Environment," Rev. 0

The inspectors also observed licensee personnel conduct inspections of a sample population of Eaton cable splices.

b. <u>Observations and Findings</u>

In LER 50-424/97-004, the licensee stated that there were no previous similar events. However, the licensee's broadness review identified DCs associated with LER 50-424/96-005, Rev. 1, as being examples of the same issue; specifically, improper Eaton cable transition splices. Additionally, the Training Department review and subsequent lesson outline (MA-LP-97007-00) identified this as a similar issue. Although LER 50-424/97-004 did not specify LER 50-424/96-005, Rev. 1, as a similar issue, the corrective actions and follow-up sampling would not have changed significantly if it was identified as a similar issue.

The licensee conducted a root cause investigation of this event and was unable to determine why the splices were improperly installed. An evaluation of the splice installations identified in the LER was conducted by contract personnel. The specific splices were determined to be environmentally qualified. Three of the four corrective actions for LER 50-424/97-004 were completed and appropriately documented. The fourth corrective action, a broadness review, remained open, due to open items within the corrective action, although the broadness review was completed. The broadness review included a plan to sample 80 splices (40 per unit) during the upcoming Unit 1 and Unit 2 refueling outages. At the time of this inspection the Unit 1 sampling was in its initial stages. The inspectors observed four satisfactory inspections on September 25, 1997; two others were already completed by the licensee and were determined to be satisfactory. Prior to the end of the inspection period the licensee completed the sampling on Unit 1. No improperly spliced cables were identified within the scope of the program. However, six splices, outside the sampling scope, were identified as not meeting the requirements of the installation drawings. The instrumentation affected by these six splices was not required to function or required to provide indication during post-accident conditions. The inspectors determined this issue to be a compliance issue with the construction drawings only. The licensee's LER commitment will remain open through the Spring 1998 Unit 2 refueling outage in order to track these sampling results.

c. Conclusions

The inspector concluded that the corrective actions for Unit 1 were completed. Based on this review, LER 50-424/97-004 is closed. To evaluate the Unit 2 inspection sampling program, Inspector Follow-Up Item (IFI) 50-425/97-10-05, Unit 2 Eaton Cable Splice Sampling, was opened.

E8.3 Maintenance Rule Implementation

a. Inspection Scope (92902)

During the inspection of corrective actions for LER 50-424/96-005, Rev. 1, and LER 50-424/97-004, Maintenance Rule implementation was also evaluated. MWOs, DCs, event investigations, root cause analysis, and plant procedures concerning Maintenance Rule implementation, were reviewed. Those items reviewed are listed below:

- Procedure 00150-C, "Deficiency Control," Rev. 23
- Procedure 00353-C, "Maintenance Rule Implementation," Rev. 4
- Procedure 50028-C, "Engineering Maintenance Rule Implementation," Rev. 5
- Procedure 80014-C, "Handling of Deficiency Cards," Rev. 11
- Procedure 81030-C, "Preparation And Processing Of Draft Licensee Event Reports And Technical Specification Reports," Rev. 2

b. Observations and Findings

During the inspectors' review of LER 50-424/97-004, an issue involving the Maintenance Rule was raised, regarding DC 1-97-173. The associated Root Cause and Corrective Action (RCCA) report was not appropriately completed, in that, the question concerning the determination and documentation of the event classification as a Maintenance Preventable Functional Failure (MPFF) was not answered. The licensee opened DC 1-97-561 to address this specific issue. DC 1-97-173 and other DCs associated with the RCCA (DC 1-97-126 and DC 1-97-132) were subsequently reviewed and determined to not be MPFFs. Additionally, the licensee reviewed approximately 75 RCCAs from the same time period and identified no other instances where MPFF determinations were not completed. The MPFF evaluations for DC 1-97-173, DC 1-97-126, and DC 1-97-132 were delayed approximately 4 months, which caused untimely MPFF determinations.

The process uses a variety of procedures to ensure that deficiencies are reviewed against the MPFF criteria. However, based on the inspectors' review, it was difficult to ascertain who was responsible to ensure that items or issues identified on DCs related to LERs were reviewed to determine if they represented an MPFF. In the case of an LER, the DC procedure also sends the individual to the draft LER procedure which is done in series with the DC process. The draft LER procedure does not reference the Maintenance Rule. In the deficiency control procedure, itis implied that it is up to the final review by Nuclear Safety and Compliance personnel and the responsible department manager to identify and document MPFFs. This process deficiency could cause delays in determining whether a system was required to be placed in the Maintenance Rule (a)(1) category.

c. Conclusions

The inspectors concluded that the process to document and determine if an LER issue qualified as an MPFF is weak in that it does not ensure timely determinations, nor is it clearly proceduralized. In addition, the responsibility to document and determine if an LER issue qualified as an MPFF is also not clearly proceduralized. Although the specific examples of untimely MPFF determinations were not safety-significant, the lack of clear guidance for MPFF determinations in the area of the deficiency card review process was identified as a weakness.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Lower Guide Tube Removal Activity

a. Inspection Scope (71750)

The inspectors reviewed the licensee's preparations and implementation of the activities to remove a damaged lower guide tube from inside containment. The inspectors reviewed the health physics radiological surveys, a safety evaluation for movement, storage, and restraint of the lower guide tube cask, Procedure (Chem-Nuclear Systems) TR-OP-045-42905, "Handling Procedure For Irradiated Hardware Shipments In The FSV-1 Cask," Revision (Rev.) 1, and various lower guide tube vendor drawings.

b. Observations and Findings

The licensee determined that the lower guide tube would be removed due to suspected damaged caused when a control rod shaft was dropped from approximately six feet above the upper guide top opening. The licensee termined that both the drive shaft and guide tube were required to be moved and replaced to ensure integrity of the upper internals mponents.

The radiological surveys completed prior to removal of the lower guide tube from the reactor cavity ind ated the highest dose rate at 686 Rem/hour. In preparation for removal of the guide tube the license took the appropriate radiological precautions necessary in handling an item with excessively high dose rates. Lead shielding was placed in certain areas in containment to protect workers from exposure to the guide tube as it was raised out of the reactor cavity. In addition, personnel access to containment was strictly limited by health protection management to only essential personnel during the removal activities.

On October 13, 1997, the licensee performed removal and storage activities of a lower guide tube from inside containment. Removal and storage activities were well controlled, coordinated, and in accordance with the vendor procedure. The lower guide was removed and stored inside a cask without incident. Due to the shielding provided by the cask survey measurements indicated that the dose rates were reduced to approximately less than 10 mrem/hour.

c. Conclusions

The inspectors concluded that the removal and storage activities for the lower guide tube were well controlled, coordinated, and in accordance with the vendor procedure. Worker precautions were appropriate. The licensee's awareness of radiological and personnel safety associated with this activity was identified as a strength.

R3 RP&C Procedures and Documentation

R3.1 Contaminated Worker Leaves Site Unauthorized

a. Inspection Scope (71750)

The inspectors reviewed the circumstances surrounding the self-decontamination activity performed by a Westinghouse contract employee on October 3, 1997. The inspectors reviewed the licensee's Procedure 00930-C, "Radiation and Contamination Control," Rev. 15, and Procedure 00920-C, "Radiation Exposure Limits and Administrative Guidelines," Rev. 13, the deficiency card generated, personnel statements, and the health protection department's dose equivalent calculation for the exposed individual. In addition, the inspectors discussed the event with licensee health protection management.

b. Observations and Findings

On October 3, 1997 health protection personnel received a call from a regarding an alarm on a gamma portal monitor located at the Alternate Plant Employee Security Building (APESB). A review of the sequence of events, based on collected personnel statements, were as follows: an employee entered the APESB; stepped into a gamma portal monitor "alarmed" the gamma portal monitor; proceeded over to the security badge island to speak with a security officer; employee was told to wait for health protection assistance by security officer; employee went outside the APESB; removed his shoes and socks; put his shoes back on; stepped into the gamma portal monitor (a second time); received a "cleared" signal; exited the protected area; and left the site. The socks were retrieved by a health protection representative. The socks were subsequently surveyed and determined to have a "discreet particle" measuring approximately 40,000 dpm/probe area. The licensee informed the inspectors that it was determined that the contractor most likely picked up the discreet particle while inside containment in and around the steam generator platforms. No other incidents of discreet particles were identified during the outage.

The dose equivalent calculation performed by the licensee determined that a maximum exposure (total dose) to the individual was approximately 1529 mrem. This calculation was based on the assumption that the particle was on the employee's sock for the employee's entire shift (i.e., 12 hours). Through further investigation, the licensee was able to identify the employee involved in the radiological incident. The inspectors were informed that the employee's badge access was terminated on October 4, 1997.

Procedure 00930-C establishes the requirements and responsibilities for monitoring and controlling exposure to radiation and contamination. Procedure 00930-C requires that health protection personnel to be immediately notified whenever contamination is detected on any individual or their personal articles. Plant personnel are not to perform self-decontamination without health protection personnel present.

c. Conclusions

On October 3, a contract employee performed self-decontamination without the assistance of health protection personnel. After alarming a gamma portal monitor the employee removed his socks, "cleared" the monitor, and subsequently left the site unauthorized. The inspectors concluded that the action by the contract employee was contrary to the requirements of Procedure 00930-C. The licensee's corrective actions were adequate and the subject employee was terminated from further employment at the plant. Consistent with Section VII of the NRC

Enforcement Policy this was identified as NCV 50-424/97-10-06, Improper Self-Decontamination by Contract Employee.

V. Management Meetings and Other Areas

X Review of Updated Final Safety Analysis Report (UFSAR)

A recent discovery of a licensee operating its facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on November 4, 1997. The licensee acknowledged the findings presented.

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

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Beasley, Nuclear Plant General Manager
J. Gasser, Plant Operations Assistant General Manager
B. Burmeister, Manager Engineering
S. Chestnut, Manager Operations
K. Holmes, Manager Maintenance
I. Kochery, Superintendent Health Physics Department
M. Sheibani, Nuclear Safety and Compliance Supervisor
C. Tippins, Jr., Nuclear Specialist I

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 61726: Surveillance Observation
IP 62707: Maintenance Observation
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 73753: Inservice Inspection
IP 92901: Followup - Operations
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering

ITEMS OPENED AND CLOSED

Opened

Type	Item Number	Status	Description and Reference
VIO	50-424/97-10-01	Open	Mis-Positioned Unit Heater Breakers on 480-volt MCC 1NBG (Section O2.2)
NCV	50-424/97-10-02	Open	Failure of Contractor Examiner to Follow MT Procedure (Section M1.3)
NCV	50-424, 425/97-10-03	Open	Improperly Set RTS and ESFAS Trip Setpoints (Section M8.1)
VIO	50-424/97-10-04	Open	Failure to Take Adequate Corrective Actions to Revise the APEX Users Manual (Section E3.1)
IFI	50-425/97-10-05	Open	Unit 2 Eaton Cable Splice Sampling (Section E8.2)
NCV	50-424/97-10-06	Open	Improper Self-Decontamination Performed by Contract Worker (Section R3.1)

Closed

VIO	50-424/97-04-01	Closed	Containment Debris Identified During 1P1 (Section O8.2)
VIO	50-425/96-11-02	Closed	Improperly Performed Surveillance to Closeout Unit 2 Containment (Section O8.2)
IFI	50-424, 425/97-08-01	Closed	Resolution of Self-Assessment Findings (Section O8.3)

LER	50-424/97-006	Closed	Hydrogen Monitoring System Train Rendered Inoperable (Section 08.4)
NCV	50-424/97-10-02	Closed	Failure of Contractor Examiner to Follow MT Procedure (Section M1.3)
NCV	50-424, 425/97-10-03	Closed	Improperly Set RTS and ESFAS Trip Setpoints (Section M8.1)
URI	50-424, 425/95-27-03	Closed	Proper Calibration of Reactor Trip System and ESFAS Trip Setpoints (Section M8.1)
LER	50-424/96-005-01	Closed	Unqualified Cabling Used in Containment Sump Level Transmitters (Section E8.1)
LER	50-424/97-004	Closed	Unqualified Cables Renders Atmospheric Relief Valves Inoperable (Section E8.2)
NCV	50-424/97-10-06	Closed	Improper Self-Decontamination Performed by Contract Worker (Section R3.1)