U. S. NUCLEAR REGULATORY COMMISSION (NRC)

REGION II

Docket Nos.	50-424 and 50-425
License Nos.	NPF-68 and NPF-81
Report No:	50-424/96-10, 50-425/96-10
Licensee:	Georgia Power Company (GPC)
Facility:	Vogtle Electric Generating Plant, Units 1 & 2 (VEGP)
Location:	7821 River Road Waynesboro, GA 30830
Dates:	August 18 - September 28, 1996
Inspectors:	C. Ogle, Senior Resident Inspector M. Widmann, Resident Inspector K. O'Donohue, Resident Inspector (in training) J. Shackelford, Reliability and Risk Analyst, NRR (Section M3.1) R. Frahm Jr., Operations Engineer, NRR (Section M3.1) E. Christnot, Resident Inspector, Hatch (Section M1.5) T. Ross, Senior Resident Inspector, Farley (Section O8.1 and E8.1)
Approved by:	P. Skinner, Chief Projects Branch 2 Division of Reactor Projects

Enclosure 2

EXECUTIVE SUMMARY

Vogtle Electric Generating Plant, Units 1 and 2
NRC Inspection Report 50-424/96-10, 50-425/96-10

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection. In addition, it includes the results of announced inspections by two visiting resident inspectors and two headquarters personnel.

Operations

- In general, the conduct of operations was satisfactory (section O1.1).

- Plant control was good, procedures were used, and appropriate trending of data was observed by the inspectors during the shutdown of Unit 2 (section O1.3).

- A non-cited violation was identified for improperly implementing a procedure used to drain the pressurizer relief tank (section O1.4).

- A violation was identified as a result of 1-HV-8220, reactor coolant system hot leg post accident sampling system (PASS) isolation valve, being in the improper position for approximately 55 hours. This is a containment isolation valve whose position is indicated in the control room. This is a repeat event (section O2.2).

- The inspectors identified examples of minor deficiencies involving caution and hold tags (section O3.1).

- Independent Safety Engineering Group (ISEG) assessments of outage risk were identified as a positive example of licensee self-assessment (section O7.1)

Maintenance

- In general, maintenance and surveillance activities witnessed by the inspectors were satisfactorily performed (section M1.1 and M1.2).

- As part of the licensee's routine monitoring program, debris was identified in a nuclear service cooling water line to the safety injection pump 1A lube oil cooler (section M1.3).

- A non-cited violation was identified as a result of an improperly established relay calibration procedure. The procedure specified installing a mechanical block in the relay during the calibration but did not provide instructions for removing the block (section M1.4).

- An Inspector Followup Item (IFI) was identified in the area of safety assessment associated with taking equipment out of service with respect to 10 CFR 50.65 (a)(3), Maintenance Rule. Several weaknesses with the licensee's implementation of the Maintenance Rule were noted (section M3.1).

Engineering

- Inspector concerns regarding observed practices were identified during the performance of main steam relief valve testing. While these practices did not impact the operability of the valve, the concerns were provided to licensee management for consideration (section E2.1).

- The licensee was complying with the provisions of its boraflex surveillance program. The current interim compensatory measures developed to mitagate the ongoing degradation of boraflex were well thought out, conservative, and supported by sound engineering judgement and evaluations. Compensatory measures were evaluated pursuant to 10 CFR 50.59, incorporated into the updated UFSAR and plant procedures, and implemented. An unresolved item (URI) was identified for some spent fuel pool (SFP) boraflex concerns pending receipt and review of the lecensee's response to generic letter (GL) 96-04 (section E8.1).

Plant Support

- A violation was identified concerning an unsecured designated vehicle in the protected area (section S3.1).

Report Details

Summary of Plant Status

Unit 1

Operated at full power throughout the inspection period.

Unit 2

The inspection report period began with the unit coasting down from 100% power in preparation for the Unit 2 fifth refueling outage (2R5). Unit 2 completed 412 days of continous run prior to shutdown. The unit shutdown was commenced on September 8, with entry into mode 5 occurring on September 9, 1996. Mode 6 was attained on September 13, and fuel offload completed on September 18, 1996. Reload of the fuel into the reactor vessel was in process on September 28th.

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 conduct of operations was satisfactory.

O1.2 Unit 2 Shutdown (71707)

The inspectors witnessed the Unit 2 shutdown activities in preparation for the 2R5. This included observation on September 7-9, 1996 of selected sections of the following evolutions: power reduction and entry into mode 2 (Procedure 12004-C, Power Operation); entry into mode 3 (Procedure 12005-C, Reactor Shutdown to Hot Standby); entry into mode 4 (Procedure 12006-C, Unit Cooldown to Cold Shutdown); and placing the residual heat removal system (RHR) in service (Procedure 13011, Residual Heat Removal System).

Plant control was good, procedures were used, and appropriate trending of data was observed by the inspectors.

O1.3 Core Offload (60710)

The inspectors witnessed portions of activities related to core offload and fuel handling in the spent fuel pool per Procedures 93300-C, Conduct of Refueling Operations; 93641-C, Development and Implementation of Fuel Shuffle Sequence Plan; and FP-GAE/GBE-FE3, Vogtle Canister Sipping

Procedure. The activities reviewed in the spent fuel pool included fuel shuffle to prepare for core reload, fuel mapping to verify the assemblies were positioned in accordance with the fuel shuffle data sheets, and fuel sipping of assemblies from 2R5.

Overall, the conduct of the core offload was in accordance with procedures and the evolutions witnessed by the inspectors in the spent fuel pool were satisfactorily performed.

O1.4 Pressure Relief Tank (PRT) Draindown Procedure Not Properly Implemented

a. Inspection Scope (71707)

The inspectors reviewed the circumstances surrounding the draining of the Unit 2 PRT on September 11, 1996 without nitrogen being aligned to the tank. This included a review of Procedures 13004-2, Pressurizer Relief Tank Operation; 13201-2, Gaseous Waste Processing System; and the integrated plant computer trend plots of PRT pressure and level. The inspectors also interviewed cognizant operators and reviewed logs on the issue.

b. Observations and Findings

On September 11, 1996, operations personnel draining the PRT, observed unexpected changes in PRT pressure, level, and reactor coolant drain tank pump flow. The draindown was stopped and the licensee determined that the PRT pressure had been reduced to approximately zero pounds per square inch gauge (psig) as a result of nitrogen being isolated to the PRT. The inspectors were subsequently informed by the licensee that their examination of the tank and review of later system operation revealed no damage. The inspectors independently inspected the PRT and noted no deficiencies.

The draining of the PRT had been immediately preceded by PRT venting using a waste gas compressor in accordance with Section 4.4.4 of Procedure 13201-2. During this venting, nitrogen was isolated to the PRT by means of a manual isolation valve. When the desired PRT pressure reduction had been accomplished, the waste gas compressor was stopped and a partial restoration performed. The manual nitrogen isolation valve was not reopened prior to draining the PRT per Procedure 13004-2. The inspectors were informed that only a partial restoration from the venting lineup was performed to facilitate venting the PRT again after it had been drained.

During their review, the inspectors determined the following:

- The transition between PRT venting and draining was not properly accomplished. Not opening the manual nitrogen supply valve prior to exiting the venting evolution resulted in not satisfying a prerequisite and initial condition of Procedure 13004-2. Some

operators involved were aware that only a partial restoration was performed following venting. However, the impact of this partial restoration was not properly evaluated.

- The operators failed to abide by a caution in Procedure 13004-2 requiring that a positive pressure of 3-5 psig be maintained within the PRT while draining. Prior to starting the draindown, PRT pressure was approximately 1 psig, outside the range specified in the caution. When questioned on this discrepancy the cognizant operators indicated that they were aware of the initial PRT pressure as well as the caution. The inspectors noted that this practice is not consistent with routine inspector observations on procedural compliance.

- The unexpected changes in PRT pressure, level, and reactor coolant drain tank pump flow were detected after several minutes of draining by inquisitive operators. However, an earlier opportunity to detect the isolated nitrogen supply was missed when the control room operator failed to detect no change in PRT pressure upon opening two other nitrogen supply valves.

Planned corrective actions identified by the licensee included revising the procedure and counselling the responsible operators.

c. Conclusions

Technical Specification (TS) 6.7.1 requires that written procedures shall be established, implemented, and maintained. The inspectors concluded that Procedure 13004-2 was not properly implemented in that an initial condition to properly align nitrogen to the PRT was not met prior to draining the tank. Furthermore, operators failed to maintain adequate nitrogen pressure in the tank. This is contrary to the requirements of TS 6.7.1. However, consistent with Section VII of the NRC Enforcement Policy this was identified as non-cited violation (NCV) 50-425/96-10-01, PRT Draindown Procedure Not Properly Implemented.

O2 Operational Status of Facilities and Equipment

O2.1 Testing Performed In Response To Industry Control Rod Insertion Problems

a. Inspection Scope (71707)

The inspectors witnessed portions of licensee actions taken in response to industry problems involving control rod performance. These problems were the subject of NRC Bulletin 96-01, Control Rod Insertion Problems. Activities witnessed by the inspectors included a manual reactor trip and rod cluster control assembly (RCCA) drag testing.

b. Observations and Findings

During the Unit 2 reactor shutdown on September 8, 1996, the licensee conducted a pre-planned reactor trip from approximately 3% power. The trip was initiated with control bank D at 138 steps and all other rods fully withdrawn. The inspectors observed that all rods fully inserted. Later in the report period, the inspectors also reviewed a video tape recording made of the digital rod position indications during the trip and again noted all rods fully inserted.

On September 23, 1996, the inspectors witnessed portions of RCCA drag testing performed in the spent fuel pool (SFP). This testing was conducted in accordance with Westinghouse Procedure STD-FP-1996-7686, Rev. 0, RCCA Drag Force Testing. In this testing, a load cell was used to measure the drag forces associated with withdrawal and insertion of each RCCA over approximately 9 feet of movement. The licensee stated that all 53 rodded assemblies from the previous cycle were satisfactorily tested in this fashion. Based on their independent review of the drag test data, the inspectors concurred with the licensee's assessment.

The inspectors also noted that the licensee elected to test all 53 rodded assemblies although they were only required to test 22. The 22 assemblies tested were based on once burned rodded assemblies over 29500 Megawatt Days/Metric Tons of Uranium (MWD/MTU) and all twice burned rodded assemblies between 43000 and 49000 MWD/MTU. The inspectors noted that testing all 53 assemblies was a conservative action on the part of the licensee.

c. Conclusions

The inspectors concluded that the testing was adequately performed in accordance with written procedures.

O2.2 Post Accident Sampling System (PASS) Valve 1-HV-8220 In Improper Position

a. Inspection Scope (71707)

The inspectors reviewed the circumstances surrounding the licensee's September 19, 1996, identification that 1-HV-8220, reactor coolant system (RCS) hot leg PASS sample isolation valve, was open instead of shut as required. The inspectors reviewed operations, and maintenance activities that may have required manipulation of this valve. This review included daily, weekly, and monthly surveillances, maintenance work orders (MWOs), in addition to primary chemistry sampling requirements performed during routine operations. The inspectors also reviewed Procedures 14905-1, RCS Leakage Calculation (Inventory Balance); 35611-C, Remote Operation of the Post Accident Sampling System; and 35614-C, Operation of the Post Accident Sampling System.

b. Observations and Findings

On September 19, 1996, during a turnover walkdown of the Unit 1 main control room boards, the oncoming balance of plant operator identified valve 1-HV-8220, RCS hot leg PASS sample isolation valve, in the open position. This is a normally closed containment isolation valve whose position is indicated by both the handswitch and main control board lights. Following identification, the valve was shut without incident using the control room handswitch.

Based on a review of the event sequence log, the inspectors determined that the valve was in the incorrect position for approximately 55 hours. The event sequence log indicates that the valve opened on September 16 at 11:39 p.m. and remained open until 7:07 a.m. on September 19. The inspectors' review of the primary chemistry log, Procedures 35611-C, and 35614-C data sheets indicated that no primary sampling was performed during that time period. The inspectors had previously identified this same valve as being in the incorrect position on September 12, 1995, and January 27, 1996. This issue was addressed as part of violation (VIO) 50-424/95-31-01, Unit 1 Post Accident Sampling System Valve In Incorrect Position and NCV 50-424/95-21-01, Mispositioned Fuel Oil Storage Tank Drain Valve and RCS Hot Leg PASS Sample Valve, respectively. The licensee had attributed these previous occurrences of 1-HV-8220 being found in the wrong position to performances of RCS leak rate calculations resulting in a pressure pulse in the piping that allowed the valve to be lifted off its seat. Once the valve partially opened, the design of the 1-HV-8220 electrical circuit sealed-in the open signal and the valve repositioned to full open. A modification was undertaken on August 26, 1996, to replace the valve with a new design based on the system application. The work was completed on September 11, 1996. A review of the Unit 1 control room log indicated that no RCS leak rate calculation was performed on September 16. A RCS leak rate was performed on September 15 at 10:59 a.m., however a review of the sequence of events log indicated that the position of 1-HV-8220 did not change as a result of this surveillance.

c. Conclusions

The inspectors noted that although the valve was improperly positioned, the valve remained operable and capable of performing its design function. Therefore, the safety consequence of the mispositioned valve was minimal. Additionally, it is noteworthy that the valve was detected to be in the incorrect position by an operator as a part of his turnover. However, the fact that the valve position information was readily available to the operators, the duration, the repetitive nature of this event, and the continuing occurrences of mispositioned valves all increase the significance of this issue.

Overall, the inspectors concluded that four shifts were not cognizant of the status of valve 1-HV-8220. This is a violation of Procedure 10000-C, Conduct of Operations, which requires shift personnel be aware of equipment component status and system lineups. This is identified as VIO 50-424/96-10-02, Unit 1 Post Accident Sampling System Valve Mispositioned.

O3 Operations Procedures and Documentation

O3.1 Walkdown of Clearances (71707)

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

29615151	RHR train B electrical and mechanical system tagout
29615181	Chemical volume and control system seal injection tagout for reactor coolant pumps 1, 2, 3, and 4
29615988	Dilution valves

The inspectors did not identify any problems or concerns during these walkdowns.

During a few routine plant tours, the inspectors identified examples of minor deficiencies involving caution and hold tags. These deficiencies were identified to control room personnel for resolution. The inspectors also discussed their observations in this area with the Operations Manager near the end of the inspection report period. The inspectors noted this was a minor degradation in the licensee's usually strong performance in this area.

O3.2 Walkdown of Miscellaneous Systems Inside Containment

a. Inspection Scope (71707)

The inspectors walked down, reviewed, and observed portions of the following activities and procedures in progress:

11899-2	RCS draindown configuration checklist (sightglass walkdown)
13005-2	Reactor coolant system and refueling cavity draining
13115-2	Containment spray system train A & B
13130-2	Post-accident hydrogen control: hydrogen monitor system train A & B
13601-2	Steam generator and main steam system operation
13615-2	Condensate and feedwater systems
23985-2	Reactor coolant system temporary water level system (reactor vessel level instrumentation)
27505-C	Opening and closing containment equipment hatch

b. Observations and Findings

The inspectors concluded that the setup of the RCS sightglass and the reactor vessel level instrumentation was in accordance with the written procedures. The necessary equipment to establish and maintain observation of the RCS and reactor vessel level was properly installed and vented. The equipment necessary for the closure of the equipment hatch in the event of an emergency was readily available inside containment. The inspectors also verified that the maintenance crew responsible for closure of the hatch was designated before each shift. No concerns or discrepancies were identified during the valve lineups and containment penetration walkdowns conducted.

O7 Quality Assurance in Operations

O7.1 Licensee Self-Assessment Activities (40500)

The inspectors reviewed multiple licensee self-assessment activities including:

- Two (2) Plant Review Board (PRB) meetings (September 10 and September 17)
- Safety Audit and Engineering Review post-audit conference for a materials control audit
- ISEG assessments of shutdown risk during the 2R5 (dated September 10, 13, 18, 20, and 24)
- Near Miss reviews 96-10 and 96-11

The ISEG assessments of outage risk were timely and provided specific recommendations to plant management on measures that could be taken to enhance plant posture relative to outage risk. This was identified as a positive example of licensee self-assessment.

No concerns were identified. The inspectors concluded that the self-assessment activities observed were effective.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) VIO 50-425/95-11-01: Loss of Containment Integrity During Refueling

The licensee submitted its reply to the NRC Notice of Violation by letter dated May 22, 1995. The inspector reviewed the corrective actions detailed in this letter. These corrective actions included

training of all responsible organizations and the establishment of a unique computer code in the nuclear plant management information system (NPMIS) database for plant components that could potentially impact containment integrity. The inspector reviewed the training lesson plans and handouts used to discuss this event with Operations, Maintenance and Work Planning group. The licensee also provided the inspector with a demonstration on the capability of generating status reports of all MWOs, surveillance test procedures and clearances that could affect containment integrity by utilizing the Integrated Leak Rate Test coding in the NPMIS database. Based on this review, this VIO is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Work Order Observations

a. Inspection Scope (62707), (62703)

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

Work Order No.	Components
29501197	2-1201-U4-251, RHR loop 1 hot leg suction bypass check valve replacement
29502837	Engineered safety features chiller modification design change package (DCP) 94VAN0033
29600304	Motor driven auxiliary feedwater (MDAFW) pump train A outboard bearing replacement
29600316	2-HV-8701B, RHR loop 1 suction isolation valve; replace gears and convert to SB actuator per DCP 95V2N0023 (electrical)
29600926	2-HV-8702B, RHR loop 2 suction isolation valve; motor operator changeout and conversion to SB-1 actuator (mechanical)
29600929	SFP fuel shuffle prior to core reload
29601038	Steam generator 1 and 3 sludge lancing
29601067	Diesel generator train 2B mechanical maintenance
29601280	Pressurizer 2-PSV-8010A, B, and C code safeties removal
29602104	MDAFW pump train A bypass discharge line orifice installation; DCP 95V2N0019
29602164	Pressurizer level transmitter, LT-0460, low side root valve replacement
29602326	Diesel generator train 2A mechanical maintenance

b. Observations and Findings

The observed maintenance activities were satisfactorily performed.

M1.2 Surveillance Observation

a. Inspection Scope (61726)

The inspector observed portions of the following surveillance activities:

Surveillance	Description
14005-2	Shutdown margin and Keff calculations
14928-2	Containment ventilation isolation-refueling
14905-2	RCS leakage calculation
24531-2	Pressurizer level protection channel III 2L-461 analog channel operational test and channel calibration
24991-2	Protection group II solid state protection system input relay test
28916-C	Containment type B & C leakage totalization

b. Observations and Findings

The observed surveillances were satisfactorily performed.

M1.3 Nuclear Service Cooling Water (NSCW) System Debris

a. Inspection Scope (62707)

The inspectors reviewed the details associated with the licensee's identification of debris in the Unit 1 NSCW system.

b. Observations and Findings

On September 17, 1996, during a routine surveillance, the licensee measured NSCW system flow to the safety injection pump 1A lube oil cooler at 7.1 gallons per minute (gpm). Though this flowrate was below the surveillance acceptance criteria, it was above a previously calculated minimum, hence the pump remained operable. Later that day, the pump was removed from service and the lube cooler flow orifice flushed. Two small pieces of metal were removed by the flush and post-flush flow through the orifice returned to normal. The inspectors examined the debris and noted that the material was similar to material previously identified as pump bearing material.

c. Conclusions

The program to identify and removed debris from the NSCW System has identified another instance of debris in the NSCW lines to a safety related component.

M1.4 Diesel Generator Underfrequency Relay Calibration

a. Inspection Scope (61726)

The inspectors reviewed the circumstances surrounding the identification of a mechanical contact block inside an underfrequency relay on diesel generator (DG) 2B on September 7, 1996. The event was reviewed to determine the adequacy of the controls during the calibration process and if the problem documented per deficiency card (DC) 2-96-081 potentially affected more relays than just the DG underfrequency relay. As a result of this event the inspectors reviewed Procedures 13145-2, Diesel Generators, 23278-C, Westinghouse Type KF Underfrequency Relay Calibration, the MWO used to perform the calibration, and the DC associated with the event. The inspectors also interviewed the instrumentation and control (I&C) technician involved, the system engineer, a systems electrical engineer, a maintenance I&C procedure writer, and licensee management as to their review of this issue.

b. Observations and Findings

On September 7, at approximately 10:21 a.m. the DG was started for the monthly operability test. Upon starting, annunciator ALB38-D06, Diesel Generator 2B Generator Underfrequency, illuminated. I&C was notified to investigate. A piece of paper was identified blocking the cylinder unit contacts closed inside the underfrequency relay. After removal of the obstruction, the DG was successfully paralleled with 2BA03 4160V bus and the surveillance 14980-2, Diesel Generator Operability Test, was completed satisfactorily.

The inspectors' review of maintenance activities identified that an underfrequency relay calibration had been completed the previous day. During the calibration, the technician was required to block closed the relay cylinder unit contacts to simulate the underfrequency condition. However, a review of Procedure 23278-C by the licensee identified that the procedure did not contain a step to remove the block once installed.

The inspectors' review of other relay calibration procedures for diesel generators identified one additional procedure that did not address the removal of the blocking mechanism before restoring the device to service (Procedure 23227-C, G.E. Type CEH51A Loss of Excitation Relay Calibration). In addition, the licensee identif.ed nine additional

procedures that did not contain an independent verification to ensure the device used to block contacts was removed. As corrective action the licensee stated their intention to revise the procedures to incorporate the necessary steps to address these issues.

c. Conclusions

The inspectors concluded that although the relay block would prevent synchronizing the diesel to the 4160 bus, the diesel remained operable and capable of performing its design function. Specifically, the relay did not impact the emergency starting and loading of the diesel. Therefore, the safety consequences of the underfrequency relay being blocked closed were minimal. However, the relay calibration procedure was not properly established as required by TS 6.7.1, Procedure and Programs. Consistent with Section VII of the NRC Enforcement Policy this was identified as NCV 50-425/96-10-03, Inadequate Procedure For Westinghouse Type KF Underfrequency Relay Calibration.

M1.5 Nuclear Safety Cooling Water Pump 1 Trip (Unit 1)

a. Inspection Scope (62707)

The inspectors reviewed maintenance activities involved with a NSCW pump 1 trip which occurred during relay testing. The activities were performed under MWO 19601884. Discussions were held with maintenance personnel, control room operators, and supervisors.

b. Observations and Findings

During the performance of Procedure 14622-1, Slave Relay Test, NSCW Pump 1 tripped approximately one minute after starting. It was also observed that the breaker, 1ABB22, for the pump discharge valve, 1HV-11600, had tripped. The breaker was reset and the discharge valve was stroked successfully. The pump was restarted and tripped after one minute and six seconds. The discharge valve started opening 59 seconds after the start of the pump and tripped 15 and one-half seconds later. The breaker was reset and the valve stroked closed. As part of the troubleshooting activities the breaker was tested and no deficiencies were observed. Maintenance personnel determined that due to timer drift the following occurred.

- The pump was started and the 45 second sequence began. This allows the pump to come up to speed and pressure before the discharge valve opens.

- The valve did not start to open until approximately 57 seconds after pump start.

- At the 70 second sequence the discharge valve should be full open.

- Due to the valve opening starting approximately 12 seconds late, when the 70 seconds sequence ended, the valve was not fully open.

- The pump logic sensed this and tripped the pump. This gave an immediate close signal to the discharge valve which was in the process of opening.

- The close signal was inserted into a valve that was moving in the open direction. This rapid reversal caused the breaker to sense an overcurrent condition and trip.

Maintenance personnel reset the time sequences to their proper values and performed a satisfactory calibration check on the agastat timer relay.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 <u>Diesel Generator Crankcase Cracks (62707)</u>

On September 9, 1996, during pre-maintenance testing of the DG 2A, two cracks were identified by the licensee on the crankcase. The licensee's inspection of the other remaining DGs revealed similar cracks on all the DGs. The cracks are located at the corners of the crankcase where the crankcase flange bolts to the base of the engine. The cracks are in the fillet radius of the flange and on the vertical face of the crankcase. The licensee's initial determination has concluded that the cracks stem from a downward bending force applied to the flange. According to the DG vendor the most likely source of the bending forces was a relaxation of the hold-down bolts. As corrective action the licensee has torqued the DG 2A crankcase holddown bolts. The licensee plans to map and monitor the cracks at scheduled maintenance intervals of 18 months for change.

The inspectors were informed by the licensee that the cracks did not represent a challenge to the operability of the engines. This conclusion was based on correspondence with the engine vendor that stated that the cracks are outside the main structural force lines and will not propagate into a load carrying member of the crankcase. The inspectors reviewed this correspondence and have no further questions in this area.

M3 Maintenance Procedures and Documentation

M3.1 Plant Safety Assessments Before Taking Equipment Out of Service

a. Inspection Scope (62707)

Paragraph (a)(3) of 10 CFR 50.65 states, in part, that the impact on plant safety should be taken into account before taking equipment out of service for monitoring or preventive maintenance. The inspectors reviewed the licensee's procedures that were used to implement this requirement and discussed the process with appropriate licensee personnel.

b. Observations and Findings

The inspectors reviewed the licensee's program and practices associated with the 50.65 (a)(3) safety assessments conducted prior to removing plant equipment from service. The site Maintenance Rule Coordinator indicated that Vogtle's maintenance rule program was designed and implemented in accordance with Nuclear Utilities Management and Resources Council (NUMARC) 93-01, Industry Guidance for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants. NRC Regulatory Guide (RG) 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, endorses NUMARC 93-01 as an acceptable method for complying with the provisions of 10 CFR 50.65. RG 1.160 states that the methods described in the guide will be used to determine compliance with 10 CFR 50.65, except in those cases when a licensee proposes an acceptable alternative method for complying with the regulations. In particular, NUMARC 93-01 states that the development of an approach to assess the impact on overall plant safety functions upon removal of structures, systems, or components (SSCs) from service consists of three steps: (1) identify key plant safety functions to be maintained; (2) identify SSCs that support key plant safety functions; and (3) consider the overall effect of removing SSCs identified above from service on key plant safety functions.

Vogtle's maintenance rule program was described in Procedure 00353-C, Revision 2, Maintenance Rule Implementation. Section 3.5 of 00353-C indicated that the Manager of Outages and Planning was responsible for assessing the effects on the performance of the plant when performing elective maintenance activities on safety-related or risk significant systems. Section 4.5 of 00353-C, Removal of Equipment for Service, described Vogtle's program for meeting the requirements of the overall plant safety assessment portion of (a)(3) of the maintenance rule. This description simply stated that use of existing programs such as the 28 day schedule, Plan of the Day meetings, and fragnets are methods for accomplishing this assessment. The procedure did not incorporate any of the aforementioned guidance as prescribed by NUMARC 93-01. Additionally, the inspectors conducted interviews with the plant personnel who were assigned the responsibility to conduct the

assessments required by Vogtle administrative procedure 00353-C as well as other key plant operations personnel. It was determined that none of the individuals who were interviewed had a familiarity with the guidance contained in the NUMARC guidelines. Furthermore, it was unclear as to how the licensee considered the impact on overall plant safety for emergent work resulting from unscheduled or corrective maintenance. This process was not described by procedure, although the Manager Outages and Planning indicated that the probability risk assessment department was contacted when the plant was in an "odd configuration" meaning that more than one significant system was out of service at a given time or when established unavailability goals for a given system were exceeded.

The maintenance rule states that the assessments should be performed prior to <u>all</u> maintenance activities (including equipment monitoring) and should take into account a consideration of the <u>total</u> plant equipment which is out of service. The licensee had a plant philosophy which was documented in the form of Management Standard No. 18, Standard for Removal of Safety Related or Risk Significant Systems from Service, dated January 29, 1995. This standard governed the conduct of elective maintenance on safety related and "risk significant" equipment as defined by the licensee's maintenance rule program. The licensee's established policy was to conduct major maintenance on only one safety related/risk significant system at a time. Additionally, the philosophy was to minimize the actual out of service time for the affected equipment. However, the inspectors noted that this management standard was limited to only safety related or risk significant equipment. Additionally, the management standard was focused primarily on those activities involving major maintenance rather than using a broad interpretation of other maintenance activities such as surveillances and monitoring as specified in the NUMARC 93-01 guidance. Further, the standard did not contain meaningful guidance as to what specific methods or considerations should be employed in assessing the impact of the out of service equipment other than ensuring that the total out of service time for the affected equipment did not exceed the established maintenance rule goals.

The inspectors attended the licensee's daily planning meeting to observe the assessments associated with the daily work activities which had been scheduled. During the particular meeting which was witnessed, there was no significant maintenance either scheduled or ongoing. However, the inspectors did not observe any systematic, formal or overt safety or risk assessment in progress. The licensee indicated that the personnel involved in the planning and scheduling process implicitly used risk/safety assessment as a matter of due course in the conduct of their responsibilities. Further, a heavy reliance was placed on systems knowledge and operational experience. Thus, the licensee asserted, the assessments were considered to be an integral and implicit part of the meeting rather than a separate topic of discussion. Consequently, the licensee did not generate or maintain the records of any specific

assessment activities which may have been performed during the planning meetings. The inspectors also noted that the plant staff did not appear to be making routine use of any information or insights (other than the total maintenance unavailability data for major safety related/risk significant systems) which might have been gained by the licensee's individual plant evaluation. The inspectors acknowledged that a current equipment out-of-service/degraded daily report is discussed during the daily operations morning meeting and a copy is kept in the control room. However, this information was not observed to be used in a formal, systematic risk assessment.

The inspectors noted that the licensee's proposed method of risk assessment during shutdown and outage configurations was to use the Outage Risk Assessment Management (ORAM) methodology. Although the inspectors did not specifically review any ORAM models or assessments, the approach which was described appeared to be consistent with that used by similar facilities for outage risk management.

c. Conclusions

The lack of a detailed procedure and appropriate training for key personnel in the guidance and methods prescribed by NUMARC 93-01 was considered to be a weakness. This lack of formal guidance and training, and a heavy reliance on normal plant scheduling meetings resulted in a highly informal process. The licensee's program did not provide for the specific identification of undesirable plant configurations or any decision thresholds or criteria which could be used by the key plant personnel involved in the assessment process. The observed process was not systematic, and the lack of specific guidance and documentation of assessments made it difficult to ascertain whether the assessments which were conducted would be reproducible and consistent. There was no discernible documentation or feedback mechanism which would allow plant management or the quality assurance organization to conduct meaningful audits of the assessment process to verify compliance with the regulation and to facilitate any improvements which might be appropriate.

The lack of guidance or methods to incorporate assessments associated with emergent maintenance was also considered to be a weakness. Since emergent maintenance is by definition unexpected, the overall assessment process must be flexible enough so as to determine the new level of plant risk which results when emergent maintenance is necessary. Once the new level of risk has been assessed, then appropriate recovery or contingency actions can be evaluated.

The licensee's focus on only major maintenance activities associated with safety related/risk significant equipment was also considered to be a weakness. The inspectors acknowledged that while the scheduling philosophy appeared to be conservative, the potential impact of other less significant maintenance and surveillance activities being performed

on other equipment should also be emphasized. As noted earlier, the maintenance rule addresses the impact of a broad range of maintenance activities with respect to the total plant equipment out of service, not just major maintenance associated with safety related equipment.

Although the inspectors did not identify any potentially risk significant configurations at Vogtle, the inspectors could not conclude that the licensee's program would be effective in preventing such configurations from occurring in the future. Based on the findings, the inspectors considered that the issue of whether or not adequate assessments were being performed as prescribed by 10 CFR 50.65 and as required by the licensee's maintenance rule program constituted an IFI 50-424,425/96-10-04, Adequacy of Licensee's Maintenance Rule Evaluations.

The inspectors noted that the licensee management disagreed with the conclusions drawn concerning weaknesses in the licensee's program. The licensee acknowledged the inspectors' findings of fact regarding the structure, content, and conduct of the program, however, the licensee disagreed that these observations would provide the basis for a conclusion that weaknesses existed in the program.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Licensee Event Report (LER) 50-424/96-009: Leaking Valve Results In Fuel Handling Building Isolation

This event was discussed in Inspection Report 50-424,425/96-09, paragraph 01.3. The licensee determined that two valves in the sampling system leaked, thereby allowing the two PASS system relief valves to lift behind the PASS panel. As corrective action, the licensee replaced the suspect leaking valves as well as the relief valves. The inspectors verified the corrective actions and concluded that they were appropriate. No additional issues were revealed by the LER. This LER is closed.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Main Steam Relief Valve Testing

a. Inspection Scope (37551)

The inspectors observed portions of Unit 2 main steam relief valve setpoint testing and adjustment conducted on September 5, 1996. This included a review of the contractor's Procedure TT-96008, QA-4 Trevitest Procedure; Procedure 28210, Main Steamline Code Safety Valve Setpoint Maintenance; Technical Manual I-1137, Installation, Operation and

Maintenance for Self-Actuated Safety Valves; and the licensee's Bolting/Torquing Manual.

b. Observations and Findings

The overall evolution was well coordinated. Particularly noteworthy was the detailed pre-evolution brief conducted by the performance team. The inspectors also observed appropriate communications between the main steam valve room and the control room.

However, during the testing, the inspectors noted that the contractors performed steps not contained in their plant approved procedure. Specifically, the inspectors noted that the installation and placement of the test device was more involved than specified in the vendor's procedure. Additionally, the locknut was tightened using a nut wrench impacted by a hammer, a technique not discussed in the vendor procedure. The inspectors were subsequently provided information that the observed practices were consistent with the vendor's standard practices.

c. Conclusions

The inspectors concluded that the observed practices did not impact the setpoint of the valves.

E2.2 Pressurizer Code Safety Testing

a. Inspection Scope (37551)

The inspectors reviewed the results of pressurizer code testing due to a four-hour notification the licensee issued on September 25, 1996.

b. Observations and Findings

On September 22, during the 2R5 pressurizer code safety valve testing, all three valves, 2-PSV-8010A, B, and C, failed to lift within the TS limits of 2485 psig ($\pm$ 1%) on their initial lifts. Of the three valves, 2-PSV-8010C, lifted approximately 3.2% above the setpoint, at approximately 3565 psig. Due to the magnitude of the failed lift, a four-hour notification was made pursuant to 10 CFR 50.72 (b)(2)(i) requirements based on the licensee's belief that 2-PSV-8010C represented a potential unanalyzed condition that would significantly impact plant safety. Although results indicated that 2-PSV-8010A and 2-PSV-8010B tested outside the TS lift criteria of 2485 psig $\pm$1%, the licensee determined that the two valves did not represent a condition that would significantly compromise plant safety.

As a result of the failed lift tests, the licensee replaced the bellows and spindle on 2-PSV-8010C, and adjusted the lift pressure on 2-PSV-8010A and 2-PSV 8010B. Each valve was retested after their respective maintenance with successful results.

The licensee stated their intention to issue a LER on the Unit 2 pressurizer code safety test results. The inspectors will review the LER when issued.

E2.3 Modification To Enhance Valve Reliability

a. Inspection Scope (62707)

The inspectors reviewed implementation of DCP 94-VAN0033, Borg Warner Electric/Hydraulic Valve Modification. The inspectors reviewed the DCP, implementing MWOs for Unit 2 valves, and witnessed a portion of the DCP implementation on one valve.

b. Observations and Findings

The DCP modified the orientation of the servo-motor and hydraulic pump for several valves in the essential chill water and nuclear service cooling water systems. Additionally, an indication of hydraulic fluid reservoir level for the valves is also provided by the DCP.

The inspectors noted that the DCP package and associated work instructions were adequate. Further, these instructions were at the work site observed by the inspectors and were in use. The work observed by the inspectors was thorough with appropriate attention to detail on the part of the technician. The post-DCP testing appeared appropriate.

E8 Miscellaneous Engineering Issues (92903)

EA 93-304	01012:	Inaccurate DG Start Counts Reported in April 9, 1990 Restart Briefing and Corrective Action Letter (CAL) Response Letter.
EA 93-304	01022:	Inaccurate DG Start Counts Reported in April 19, 1990 LER.
EA 93-304	01032:	Inaccurate and Incomplete Information Reported in June 29, 1990 LER Revision.
EA 93-304	01042:	Inaccurate and Incomplete Information Reported in August 30, 1990 Letter.

These violations were issued in correspondence to GPC from the NRC dated May 9, 1990, Subject: Notice of Violation and Proposed Imposition of Civil Penalties - $200,000, and Demands for Information. Additional correspondence was sent to GPC relative to these violations on August 19, 1994 and February 13, 1995. GPC responded to these violations in correspondence dated May 27, 1994; July 31, 1994; August 17, 1994, and March 1, 1995.

NRC inspectors have reviewed the licensee's corrective actions associated with these violations. In addition, inspectors have frequently monitored activities at Vogtle to determine if the corrective actions have been effective. These reviews and monitoring activities

have concluded that the actions taken have been sufficient to preclude events such as those that formed the basis for the Notices of Violation. Based on these actions, your corrective actions for these violations appear to be effective and these violations are closed.

E8.1 (Closed) IFI 50-424/95-06-04: Accelerated Boraflex Coupon Degradation Unit 1 Spent Fuel Pool

After the fifth Unit 1 refueling outage, selected longterm and accelerated exposure boraflex coupons were removed from the Unit 1 SFP in accordance with Procedure 88020-C, Boraflex Surveillance Program Spent Fuel Pool. Subsequent laboratory analysis determined that the accelerated boraflex coupons had experienced excessive shrinkage that failed to meet the surveillance acceptance criteria for allowed dimensional changes (i.e., no greater than 2.0% change from original dimensions). DC 1-95-018 was written on March 3, 1995, to document this problem. The longterm coupons had also experienced some shrinkage. Although this shrinkage was within the surveillance acceptance criteria, the licensee became concerned that the Unit 1 criticality analyses did not explicitly allow boraflex shrinkage. DC 1-95-041 was written on May 23, 1995, to document this additional concern. In order to address these problems, the site issued request for engineering assistance (REA) 95-V1A614 to request engineering support regarding reportability, being in an unanalyzed condition, and the prospects for continued use of the Unit 1 SFP with degrading boraflex.

By letter dated June 20, 1995, the corporate office responded to the REA concluding that the current degraded condition was not reportable - an unanalyzed condition existed, but based upon an additional criticality evaluation, this condition did not significantly compromise plant safety. The REA response also provided specific recommendations regarding fuel management restrictions for the Unit 1 SFP, which included prohibiting the storage of new fuel in the Unit 1 SFP. Furthermore, a Boraflex Task Force was formed to address the longterm degradation of boraflex and consider revising the SFP rack criticality analyses. On October 23, 1995, DC 2-95-185 was written to document that the results from the analysis of Unit 2 accelerated and longterm boraflex coupons indicated shrinkage at, and slightly exceeding, the surveillance program acceptance criteria and 2.0% shrinkage limit assumed in the Unit 2 criticality safety analyses submitted to the NRC by letter dated August 12, 1988. To address the expanded scope of boraflex degradation, VEGP letter LCV-0686 dated November 8, 1995, established administrative controls for fuel management in the Unit 1 and 2 SFPs to ensure the conclusions of current criticality analyses remained valid until new analyses were conducted. These administrative controls were evaluated pursuant to 10 CFR 50.59, approved by the PRB as licensing document change request (LDCR) FS95-073 on January 3, 1996, and incorporated into the Updated Final Safety Analysis Report (UFSAR) as a revision to section 4.3.2.6.a. The November 8, 1995 letter also reconfirmed the expanded problem of Unit 1 and 2 boraflex degradation in

excess of acceptable limits was not reportable. Furthermore, it acknowledged that the administrative controls were only temporary since they were based upon predictive assumptions regarding the deteriorating conditions of boraflex in the SFP racks. Due to the uncertainties and difficulty in predicting the behavior of degrading boraflex, the licensee commenced a reanalysis of the Unit 1 and 2 SFPs to eliminate the dependence upon boraflex. Upon completion of this reanalysis and NRC approval, the temporary fuel management restrictions of UFSAR 4.3.2.6.a could be lifted.

After the sixth Unit 1 refueling outage, DC 1-96-312 was written on July 10, 1996, to document the increasing degradation of the accelerated and longterm boraflex coupons all of which failed the surveillance acceptance criteria for dimensional changes due to shrinkage. The accelerated coupons also failed to meet their surveillance acceptance criteria for change in specific gravity (i.e., no greater than 10%). But all coupons continued to meet the acceptance criteria for hardness and neutron attenuation. The effects of continued, increasing boraflex degradation was addressed by VEGP letter LCV-0854 dated July 30, 1996. This letter concluded that even with the increased boraflex degradation, and assuming no soluble boron in the SFP cooling water, the subcriticality margin requirements of TS 5.6.1.1. and original design basis (i.e., Keff less than 0.95) were still met. Furthermore, the degrading boraflex condition was not safety significant because the level of soluble boron (typical concentration about 2000 ppm) maintained in the SFP assured subcriticality well below TS and design basis requirements regardless of boraflex.

Each of the aforementioned documents, letters, DCs, UFSAR revision, surveillance procedure, and coupon analysis results were reviewed by the inspector and discussed with the responsible site reactor engineer. Two conference calls were also held on August 28 and 29, 1996, with the site reactor engineer, corporate Nuclear Fuel engineers, and NRC inspector to discuss the ongoing degradation and current design requirements of boraflex in the Unit 1 and 2 SFP racks, effectiveness of the boraflex surveillance program, interim compensatory measures and longterm corrective actions.

The administrative controls of UFSAR 4.3.2.6.a for Unit 1 and 2 SFP fuel management were incorporated into plant procedure 93641-C, Development And Implementation Of The Fuel Shuffle Sequence Plan, Revision 6, dated January 23, 1996. This procedure was reviewed by the inspector and verified to be consistent with the revised UFSAR. These administrative controls restricted the placement of any fuel assembly with less than 17100 MWD/MTU to only those Unit 2 SFP rack locations that had not previously contained an irradiated fuel assembly. One exception being, that independent of burnup a single assembly may be placed in the center of a 3X3 array of empty SFP rack locations for the purpose of fuel inspection and repair. VEGP letter ELV-05885 letter dated January 31, 1996, established the Unit 2 SFP rack locations that were suitable

(i.e., unirradiated) for storing new or low burnup fuel based on historical Unit 2 fuel shuffle sheets provided by reactor engineering. The inspector reviewed this letter, which included a marked up Unit 2 SFP map showing irradiated and unirradiated rack locations. On August 26 and 29, 1996, the inspector toured the Unit 1 and 2 SFPs and verified that the new fuel assemblies for the upcoming Unit 2 refueling outage were stored in designated, unirradiated rack locations. Furthermore, the inspector noticed that the new fuel assemblies in the Unit 2 SFP and spent fuel assemblies in the Unit 1 SFP were stored in a checkerboard fashion. This was a further conservative measure taken by the licensee.

Upon completion of this inspection followup, the inspector concluded that the licensee was complying with the provisions of its boraflex surveillance program. Also, the current interim compensatory measures developed to mitigate the ongoing degradation of boraflex were well thought out, conservative in nature, and supported by sound engineering judgement and evaluations. These compensatory measures were evaluated pursuant to 10 CFR 50.59, incorporated into the updated UFSAR and plant procedures, and implemented accordingly. Furthermore, the actual safety implications associated with continuing boraflex deterioration were insignificant based upon the established fuel management compensatory measures and the concentration of soluble boron maintained in the SFPs. However, during this inspection the following comments and/or concerns were discussed with responsible licensee engineers and plant management:

- The unirradiated Unit 2 SFP rack locations deemed acceptable for storage of new fuel were not specifically identified by an approved plant procedure (e.g., procedure 93641-C).

- Although the descriptive portion of the 10 CFR 50.59 safety evaluation dated November 9, 1995 (included as part of LDCR FS95-073) was suitably comprehensive and detailed, the Section B, <u>Safety Evaluation</u> did not adequately address all the questions related to 10 CFR 50.59(a)(2). There was insufficient detail or information in Section B, to address the consequences and/or probability of a loss of subcriticality from the malfunctioning (i.e., deteriorating) boraflex in the SFP racks to determine an unreviewed safety question did not exist.

- The present rate of boraflex deterioration could most likely exceed the bounding limits of acceptable shrinkage established by the July 30, 1996 letter. This letter concluded that TS and design basis requirements of Keff less than 0.95 were met, in the past, based on certain estimated shrinkage limits. Exceeding these limits would once again place the SFPs in an unanalyzed condition.

- Certain surveillance program implementation issues associated with boraflex coupon sampling methodology were identified (e.g., no samples have been taken from the Unit 2 control coupons to assess

deterioration due to dissolution versus radiation; accelerated erosion induced deterioration of Unit 1 coupons due to SFP cooling flow).

- The SFP rack boraflex shrinkage in excess of the design assumptions stated in the Unit 2 criticality safety analyses submitted to the NRC by letter dated August 12, 1988, could have been reported pursuant to 10 CFR 50.73(a)(2)(ii)(B) as a "condition that was outside the design basis of the plant."

Generic Letter (GL) 96-04, Boraflex Degradation In Spent Fuel Pool Storage Racks was issued June 26, 1996, with a response due from licensee's 120 days from the issue date. The comments and or concerns listed above were subsequently identified to the licensee (by the resident inspector) on October 23, 1996, as unresolved item (URI) 50-424,425/96-10-06, Spent Fuel Pool Boraflex Concerns, pending receipt and review of the licensee's response to GL 96-04.

Based on this review the IFI is closed.

IV. Plant Support

S3 Security and Safeguards Procedures and Documentation

S3.1 Designated Vehicle Unsecured Inside the Protected Area

a. Inspection Scope (71750)

The inspectors reviewed the circumstances surrounding the licensee's identification of a designated vehicle not properly secured inside the protected area on August 26, 1996. In response to this issue, the inspectors reviewed the Physical Security Plan, applicable security procedures, vehicle records, and the statement of the individual responsible for leaving the vehicle unattended. The inspectors interviewed the involved officer, the security manager, and licensee management as to their review of this event.

b. Observations and Findings

At approximately 3:02 p.m. on August 26, 1996, the licensee's security patrol identified an unattended designated vehicle, a tractor, in the protected area with the keys in the ignition. The driver was located, the vehicle physically removed from the protected area, and the designated vehicle status rescinded.

From interviews and security statements, the inspectors determined that this incident was the result of an inadvertent error on the part of a contractor. From discussion with the involved officer, the inspectors learned that the individual stated to the officer that he was aware of

the requirement to remove the keys from the vehicle but forgot to do so when he exited the vehicle.

c. Conclusions

Failure to remove keys from an unattended designated vehicle in the protected area is contrary to the requirements of procedure 00653-C. Protected Area Entry/Exit Control. This was identified as a VIO 50-424.425/96-10-05. Designated Vehicle Left Unattended Inside the Protected Area.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on October 4, 1996. 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
P. Rushton, Plant Support Assistant General Manager
J. Gasser, Plant Operations Assistant General Manager
S. Chestnut, Manager Operations
K. Holmes, Manager Maintenance
M. Sheibani, Nuclear Safety and Compliance Supervisor
E. Kozinsky, Planning & Control Supervisor
G. Hooper, Engineering Group Supervisor
D. Minyard, Engineer Senior
C. Tippins, Jr., Nuclear Specialist I
S. Kitchens, Nuclear Support General Manager
J. Bailey, Manager of Licensing
A. Farruk, Probabilistic Risk Assessment Supervisor
K. Powers, Engineer Senior

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls In Identifying, Resolving, and Preventing Problems
IP 60710:	Refueling Activities
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92700:	Onsite Notification of Written Reports of Non-routine Events At Power Reactor Facilities
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

<u>Opened</u>

50-424/96-10-02	VIO	Unit 1 Post Accident Sampling System Valve Mispositioned (Section O2.2)
50-424,425/96-10-04	IFI	Adequacy of Licensee's Maintenance Rule Evaluations (Section M3.1)
50-424,425/96-10-05	VIO	Designated Vehicle Left Unattended Inside the Protected Area (Section S3.1)
50-424,425/96-10-06	URI	Spent Fuel Pool Boraflex Concerns (Section E8.1)

<u>Closed</u>

50-425/96-10-01	NCV	PRT Draindown Procedure Not Properly Implemented (Section O1.4)
50-425/95-11-01	VIO	Loss of Containment Integrity During Refueling (Section O8.1)
50-425/96-10-03	NCV	Inadequate Procedure For Westinghouse Type KF Underfrequency Relay Calibration (Section M1.4)
EA 93-304 01012	VIO	Inaccurate DG Start Counts Reported in April 9, 1990 Restart Briefing and CAL Response Letter (Section E8)
EA 93-304 01022	VIO	Inaccurate DG Start Counts Reported in April 19, 1990 LER (Section E8)
EA 93-304 01032	VIO	Inaccurate and Incomplete Information Reported in June 29, 1990 LER Revision (Section E8)
EA 93-304 01042	VIO	Inaccurate and Incomplete Information Reported in August 30, 1990 Letter (Section E8)
50-424/96-009	LER	Leaking Valve Results In Fuel Handling Building Isolation (Section M8.1)
50-424/95-06-04	IFI	Accelerated Boraflex Coupon Degradation Unit 1 Spent Fuel Pool (Section E8.1)

LIST OF ACRONYMS USED

X. List of Acronyms Used

CFR	- Code of Federal Regulations
DC	- Deficiency Card
DCP	- Design Change Package
DG	- Diesel Generator
GL	- Generic Letter
GPC	- Georgia Power Company
I&C	- Instrumentation and Controls
IFI	- Inspector Followup Item
ISEG	- Independent Safety Engineering Group
LDCR	- Licensing Document Change Request
LER	- Licensee Event Report
MDAFW	- Motor Driven Auxiliary Feedwater
MTU	- Metric Tons of Uranium
MWD	- Megawatt Days
MWO	- Maintenance Work Order
NCV	- Non-Cited Violation
NPF	- Nuclear Power Facility
NPMIS	- Nuclear Plant Management Information System
NRC	- Nuclear Regulatory Commission
NRR	- Nuclear Reactor Regulation
NUREG	- Nuclear Regulations
NUMARC	- Nuclear Utilities Management and Resources Council
ORAM	- Outage Risk Assessment Management
PASS	- Post Accident Sampling System
PDR	- Public Document Room
PRT	- Pressurizer Relief Tank
PRB	- Plant Review Board
psig	- Pounds Per Square Inch Gauge
QA	- Quality Assurance
RCCA	- Root Cause and Corrective Action
RCS	- Reactor Coolant System
REA	- Request for Engineering Assistance
RG	- Regulatory Guide
RHR	- Residual Heat Removal System
SFP	- Spent Fuel Pool
SSC	- Structure, System, or Component
TS	- Technical Specifications
UFSAR	- Updated Final Safety Analysis Report
VEGP	- Vogtle Electric Generating Plant
VIO	- Violation
2R5	- Unit 2 Fifth Refueling Outage