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

Report Nos.: 50-424/92-04 and 50-425/92-04

Licensee: Georgia Power Company
P.O. Box 1295
Birmingham, AL 35201

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

Facility Name: Vogtle Nuclear Station Units 1 and 2

Inspection Conducted: February 23, 1992 - March 21, 1992

Inspectors:	S E Sparks B. R. Bonser, Senior Resident Inspector	4/8/92 Date Signed
	S E Sparks R. D. Starkey, Resident Inspector	4/8/92 Date Signed
	S E Sparks P. A. Balmain, Resident Inspector	4/8/92 Date Signed
Approved By:	P. A. Skinner P. Skinner, Chief Reactor Projects Section 3B Division Reactor Projects	4/16/92 Date Signed

SUMMARY

Scope: This routine inspection entailed inspection in the following areas: plant operations, surveillance, maintenance, refueling activities, review of licensee events reports, follow-up, and a review of corporate engineering and design change support.

Results: No violations or deviations were identified.

A significant portion of the inspection period was devoted to verification that the licensee had adequate procedures in place and was implementing practices to assure reliable decay heat removal during outages and maintaining adequate controls for monitoring reduced reactor water level during outages. The inspectors found the procedures and their implementation to be satisfactory. The inspectors noted that significant enhancements had been made in these programs since the last outage.

Unit 2 tripped on March 9, after operating for 306 days. The licensee decided to not restart the unit and begin the outage which had been scheduled for March 13. The cause of the trip was personnel error.

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A noteworthy increase in management involvement and visibility has been observed during the Unit 2 refueling outage. This has been evident in management tours and walkdowns in the plant, and management's involvement in infrequently performed evolutions and solution of problems.

A review of corporate engineering and design change support was performed in Birmingham, Alabama. The review found the design change process well organized with a dedicated support organization performing their work in accordance with applicable procedures and acceptable technical practices. All of the DCPs and other documentation were of good quality. There have, however, been problems in providing DCPs to the site on time for the designated work period.

DETAILS

1. Persons Contacted

Licensee Employees

*H. Beacher, Senior Plant Engineer
*J. Beasley, Assistant General Manager Plant Operations
R. Brown, Supervisor Operations Training
*W. Burmeister, Manager Engineering Support
*S. Chesnut, Manager Engineering Technical Support
*C. Christiansen, Safety Audit and Engineering Group Supervisor
W. Copeland, Supervisor - Materials
C. Coursey, Maintenance Superintendent
*R. Dorman, Manager Training and Emergency Preparedness
J. Gasser, Operations Unit Superintendent
M. Hobbs, I&C Superintendent
*K. Holmes, Manager Health Physics and Chemistry
D. Huyck, Nuclear Security Manager
*W. Kitchens, Assistant General Manager Plant Support
*R. LeGrand, Manager Operations
G. McCarley, ISEG Supervisor
A. Parton, Chemistry Superintendent
B. Raley, Plant Engineer Supervisor - Maintenance
M. Seepe, Radwaste Supervisor
*M. Sheibani, Nuclear Safety and Compliance Supervisor
*[illegible]. Shipman, General Manager Nuclear Plant
C. Stinespring, Manager Administration
J. Swartzwelder, Manager Outage and Planning
*L. Ward, Manager Maintenance - Acting

Other licensee employees contacted included technicians, supervisors, engineers, operators, maintenance personnel, quality control inspectors, and office personnel.

Oglethorpe Power Company Representative

*T. Mozingo

NRC Resident Inspectors

*B. Bonser
*D. Starkey
*P. Balmain

*Attended Exit Interview

An alphabetical list of abbreviations is located in the last paragraph of the inspection report.

2. Plant Operations - (71707)

a. General

The inspection staff reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, Technical Specifications, and administrative controls. Control logs, shift supervisors' logs, shift relief records, LCO status logs, night orders, standing orders, and clearance logs were routinely reviewed. Discussions were conducted with plant operations, maintenance, chemistry and health physics, engineering support and technical support personnel. Daily plant status meetings were routinely attended.

Activities within the control room were monitored during shifts and shift changes. Actions observed were conducted as required by the licensee's procedures. The complement of licensed personnel on each shift met or exceeded the minimum required by TS. Direct observations were conducted of control room panels, instrumentation and recorder traces important to safety. Operating parameters were observed to verify they were within TS limits. The inspectors also reviewed DCs to determine whether the licensee was appropriately documenting problems and implementing corrective actions.

Plant tours were taken during the reporting period on a routine basis. They included, but were not limited to the turbine building, the auxiliary building, electrical equipment rooms, cable spreading rooms, NSCW towers, DG buildings, AFW buildings, and the low voltage switchyard. The inspectors also made several tours of the Unit 2 containment building.

During plant tours, housekeeping, security, equipment status and radiation control practices were also observed.

The inspectors verified that the licensee's health physics policies/procedures were followed. This included observation of HP practices and review of area surveys, radiation work permits, postings, and instrument calibration.

The inspectors verified that the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the PA; vehicles were properly authorized, searched, and escorted within the PA; persons within the PA displayed photo identification badges; and personnel in vital areas were authorized.

b. Unit 1 Summary

The unit began the period operating at 100% power. On March 7, power was reduced to 90% for repair of the B heater drain tank normal level control valve. The unit returned to full power on March 8. The unit operated at full power throughout the remainder of the inspection period.

c. Unit 2 Summary

The unit began the period operating at approximately 93% power in an end-of-cycle coastdown. At 8:25 p.m., on March 9, with the unit at 80% power, the unit tripped automatically due to personnel error (see para. 2d). The unit was not restarted and the second refueling outage began following the trip. The unit had been in operation for 306 days. This was the longest operating run of either unit to date. The unit entered Modes 4 and 5 on March 11. The unit entered Mode 6 on March 16.

d. Unit 2 Reactor Trip

On the evening of March 9, the CR began receiving intermittent train A 125V DC switchgear trouble alarms on switchgear 2AD1, 2AD11, 2AD12. A PEO was sent to investigate the cause of the alarms. While checking the breakers on panel 2AD12 the PEO noticed that two of the breakers on the panel had a small yellow button in the lower right corner on the face of the breaker. Unsure of the purpose of the buttons and thinking they might be indicator flags he took a pen and depressed the yellow button on breaker 2AD12-8. The dot recessed and the breaker tripped to the mid position.

When 2AD12-8 tripped, 125V DC control power was lost to the train A MSIVs, all four MFIVs and all four BFIVs. Vogtle has two MSIVs on each steam line. One MSIV in each steam line is an A train valve and the other a B train valve. The MFIVs and BFIVs have A and B train solenoids on each valve. All these valves failed closed, as designed, isolating feedwater flow to and steam flow from the SGs. Within seconds, the RCS pressure increased to the reactor trip setpoint of 2385 psig due to the loss of the heat sink and the reactor trip occurred.

Following the trip maximum pressures reached were about 2390 psig in the RCS and 1200 psig in the steam generators. A pressurizer PORV lifted to relieve RCS pressure and main steam line ARVs and several safety valves lifted to relieve steam generator pressure. All relief valves operated normally. When SG water levels decreased to the low-low setpoint, the AFW system actuated as designed. All systems operated normally following the trip with the exception of a non-vital bus (2NA05) which failed to complete an automatic bus transfer to the RAT. This resulted in the loss of non-1E power to the auxiliary building.

At the time of the event the plant was in a coastdown, boron concentration was less than 10 ppm, and the reactor core was reaching EOL. A scheduled refueling outage was to begin on March 13. Following the trip the licensee decided to begin the refueling outage early after weighing the benefits of trying to restart the plant.

The cause of the trip was a personnel error. When the PEO depressed the yellow button on the breaker he was unaware that his actions would result in a reactor trip. The breaker was, however, plainly marked as a "Trip Hazard". Although the PEO had not been taught that the yellow button was a trip test button, operator training includes advice to personnel to request direction from supervision when unsure how to proceed. After the trip it was determined that most operations personnel had been unsure of the function of the yellow button. The buttons are not marked and on most 125V DC breakers the buttons are black like the breaker housing. Breakers that were recently replaced have yellow push buttons. The push buttons are test buttons and when depressed cause the breakers to trip.

The PEO was counseled and reminded of the importance of requesting assistance when confronted with unfamiliar conditions. Also, Operations shift briefings have been conducted to inform the operations staff of this event and the proper course of action to pursue under similar circumstances.

The inspectors had no further questions on the cause of the trip. The inspectors will review the results of the licensee's trip critique and any further corrective action.

e. Computerized Rounds

In early March, 1992, the licensee implemented the taking of computerized non-TS rounds for the Units 1 and 2 turbine buildings and outside areas. The licensee projects that within the next few months that other operator rounds will also be computerized including those data points required by TS. Computerized rounds had been in the developmental stage for several months and replaced the rounds sheets which had previously been used to record equipment condition and operating parameters. Guidance for performing computerized rounds is found in procedure 10001-C, Logkeeping.

The computerized rounds are taken using hand-held computers. At the beginning of each shift the turbine building or outside area rounds are downloaded from a control room computer. Each round is assigned on the computer to a specific operator. PEOs then take the hand-held computer to their assigned area and complete the entries. The computerized rounds are arranged such that a PEO can easily walk through his assigned rounds with little or no back tracking. However, the hand held computer does provide the capability to page forward or backward to a particular point on the rounds which gives the PEO the flexibility of taking the rounds out of the normal sequence if desired. Data is entered from the hand-held computer alpha-numeric keyboard. The entered data is compared against an acceptable range for that data point and the operator is alerted if the actual data is outside the acceptable range. Space is also provided in the data field to enter comments regarding a particular abnormal reading or observation.

When the computerized rounds are completed they are uploaded from the hand-held computer to the control room computer. Rounds are then reviewed on the computer video monitor by the USS and, if applicable, by the RO or BOP operator. They indicate their review of the rounds by typing their name in the spaces provided at the end of the round. Although a printout is not required of the entire rounds, a printout is required of each round's "out-of-spec and comments" for review by the on-coming shift PEO. In addition to approving the rounds on the computer, a Computerized Round Sign-off Sheet is completed for each round done on the computer. Completed Computerized Round Sign-off Sheets are forwarded to document control for retention. Rounds data uploaded from hand-held computers are automatically loaded onto the LAN, and then become accessible to anyone having LAN access. Once a data base is established system engineers will be able to review parameter trends for various equipment and components. Although the computerized rounds are relatively new there appears to be good operator acceptance of the system and the system has worked as expected.

f. Unit 2 Backfeed Walkdown

On March 20, the inspector accompanied the engineering support manager and the electrical system engineer on a walkdown of the Unit 2 backfeed lineup from the 500 KV switchyard to the UATs. The backfeed consists of a temporary modification which changes the plant's electrical configuration to enable a backfeed from the 500KV switchyard to the UATs to energize the 13.8 KV and 4160V non-1E busses. During normal operation the UATs are powered from the main generator. Normally when shutdown the RATs supply all 1E and non-1E loads. During outages when one of the RATs may be out of service for maintenance, backfeed is used due to capacity restrictions on a single RAT. When one RAT is tagged out for maintenance the other RAT is used to supply both 1E 4160V busses; the non-1E loads are supplied using the backfeed.

This modification does not impact offsite or onsite power supplies to the 1E busses. The backfeed will be in place for approximately one to two weeks during the Unit 2 outage. Offsite power will be available to supply both RATs. PMs for the RATs are scheduled during the defueled window. The inspector noted that procedural guidance is available for energizing the 4160V 1E busses when the backfeed is the only offsite source available, both DGs are inoperable, and either RAT can be energized.

g. OTDT Bistable Trips Due to Delta-T Drift

On February 28, Unit 1 received an OTDT alarm, OTDT trip and OTDT runback bistable actuations on loop 4 for approximately two seconds. Since the unit's startup from refueling in December 1991 there have been several OTDT trip and runback bistable actuations on loop 3. These actuations were attributed to RCS hot leg temperature streaming effects resulting from a low neutron leakage core design and the installation of thermowell mounted RTDs in the RCS loops for narrow range temperature measurement. This was discussed in NRC Inspection Report No. 50-424,425/91-32.

The loop 4 bistable actuation occurred because the measured value of delta-T on this loop increased due to T-hot drifting hotter. This increase is believed to result from a change in the temperature streaming profile measured in the RCS hot legs as the core ages and the core's radial power distribution changes. The licensee is trending the difference of average loop delta-T and average reactor power as a function of core burnup. This trend initially showed the measured delta-T on loops 2 and 4 increasing, loop 3 decreasing, and loop 1 remaining relatively stable. The trend currently shows that delta-T on loop 2 and loop 3 is decreasing, loop 1 increasing slightly and loop 4 was recalibrated.

Since the loop 4 delta-T is generally increasing, it is in the conservative direction. As T-hot drifts hotter it will cause delta-T to approach the actuation setpoint. The drift is a reliability concern, since it has resulted in bistable actuations, which could potentially contribute to an undesired transient due to a protection system actuation. Loops which exhibit decreasing delta-T are maintained within the acceptance criteria specified in procedure 88016-C, Determination of RCS Delta T at 100% Rated Thermal Power. The licensee monitors the delta-T trend on a monthly basis and compares delta-T to reactor power, and from this trend determines if there is a need to recalibrate the OTDT and OPDT protection channels.

No violations or deviations were identified.

3. Surveillance Observation (61726)

Surveillance tests were reviewed by the inspectors to verify procedural and performance adequacy. The completed tests reviewed were examined for necessary test prerequisites, instructions, acceptance criteria, technical content, data collection, independent verification where required, handling of deficiencies noted, and review of completed work. The tests witnessed, in whole or in part, were inspected to determine that approved procedures were available, equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and systems restoration was completed.

Listed below are surveillances which were either reviewed or witnessed:

Surveillance No.	Title
28210-2	Main Steam Line Code Safety Valve Setpoint Verification.
28810-2	Battery Service Check and 18 Month Inspection
14005-2	Shutdown Margin Calculations

No violations or deviations were identified.

4. Maintenance Observation (62703)

a. General

The inspectors observed maintenance activities, interviewed personnel, and reviewed records to verify that work was conducted in accordance with approved procedures, TSs, and applicable industry codes and standards. The inspectors also frequently verified that redundant components were operable, administrative controls were followed, clearances were adequate, personnel were qualified, correct replacement parts were used, radiological controls were proper, fire protection was adequate, adequate post-maintenance testing was performed, and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

Outstanding work requests were reviewed to ensure that the licensee gave priority to safety-related maintenance activities.

The inspectors witnessed or reviewed the following maintenance activities:

MWO No.	Work Description
29200614	Replace DG 2A control panel C power available light socket.
19200314	Replace control boards in battery chargers CAA and CAB with modified control boards and install new DC input capacitors.
29200564	Replace control boards in battery chargers CCA and CCB with modified control boards and install new DC input capacitors.

2?102949	Adjust main steam safety valve 2PSV3011 following lift test per procedure 28210-2.
29200852	DG2B ESF cooling fan #4 will not start when handswitch is placed in the start position.

b. Overstress Condition On Encapsulation Vessel Welds

During Unit 1's last refueling outage on October 30, 1991, the licensee identified a condition where the vessel head bolts for the Unit 1 RHR and CS encapsulation vessels were torqued to a value which exceeded the allowable stresses for the flange and flange to shell welds on the vessels.

The discovery was made following the failure of a pre-maintenance LLRT conducted on September 18, 1991, on the B RHR encapsulation vessel (penetration 36). To correct the high leakage condition, maintenance engineering increased the specified torque values for the Unit 1 encapsulation vessels. While reviewing the increased torque values in order to revise drawings, the licensee determined that the encapsulation vessels were torqued above the 125 ft-lbs specified in the original design. The licensee also requested that the encapsulation vendor recalculate the maximum allowable torque limits. The vendor then determined that the originally specified torque value of 125 ft-lbs for each vessel was incorrect. The vendor reevaluated the design and specified torque limits of 85 ft-lbs for the RHR vessels and 68 ft-lbs for the CS vessels.

The licensee took action to correct and evaluate the overstress condition by obtaining replacement gasket material, sealant specifications and appropriate torque values from the vendor (Richmond Engineering). Richmond Engineering performed a visual inspection of all four vessels and found no defects. All four of the Unit 1 vessels were reassembled using the replacement gasket material, passed post maintenance LLRT and were subsequently declared operable.

The licensee also identified an overstress condition on the Unit 2 RHR encapsulation vessels (DC 2-91-174). Since Unit 2 was operating at the time of discovery the licensee developed a JCO as immediate corrective action. The JCO was documented under Bechtel Letter No. BV-GP-00463 and based the justification on the fact that the encapsulation vessels and its guard pipe do not communicate with the containment atmosphere; the penetrations exhibited an allowable leakage rate when subjected to a Type B local leak rate test; the vessels experienced a higher internal pressure under the Type B test than is assumed to occur during a design basis accident and no other loads are assumed to challenge the integrity of the RHR encapsulation vessel seal. The inspector reviewed the JCO and concluded that the integrity of the encapsulation vessel would not be adversely affected.

During this inspection period the licensee took the following actions to verify acceptability of the Unit 2 encapsulation vessels for continued service. Prior to disassembly the licensee performed liquid penetrant tests of the affected welds on all four vessels with acceptable results. After disassembling a PWR encapsulation vessel, radiographs of a representative weld were taken and found acceptable. The vendor also visually inspected the flanges and found no damage to the flanges.

The licensee performed a root cause evaluation of this event and determined that the Bolting/Torquing Manual did not provide adequate guidance to caution against exceeding allowable flange stresses when calculating new torque values.

c. CCW System Leak

On March 16, a 1000-1500 gallon leak of CCW water into the auxiliary building occurred when maintenance personnel breached the system to repair leaking compression fittings on two valves associated with a flow instrument located on the B train CCW supply to the spent fuel heat exchanger (MWO 29100914). Prior to performing the work a maintenance foreman had signed onto the appropriate clearance as a subclearance holder but failed to observe that a functional release of the CCW supply to the SFPC heat exchanger was in effect and failed to verify the clearance was adequate to support the work. When the maintenance personnel breached the system the leak occurred because the functional release which was in effect had opened the valves which would have provided a boundary.

Procedure 00304-C, Equipment Clearance and Tagging, provides requirements for the clearance of plant equipment to ensure safety of personnel and equipment during maintenance. This procedure also provides for functional release of equipment tagged out under clearance to support operation of maintenance activities and requires plant supervisors and the foreman to verify that a clearance is adequate for the work to be performed before the work begins. In this case the foreman failed to verify that the clearance was adequate to support the work. System leaks due to functional releases being in effect have been a recurring problem during recent outages, however, the inspector concluded that this event was due to a personnel error for failure to verify an adequate clearance for the work being performed and not a procedural or programmatic inadequacy.

d. Functional Clearance Release Requested While Work In-Progress

On March 16, a contractor foreman and his supervisor went to the Clearance and Tagging desk to request a functional release of Clearance #29215016 in order that 480V switchgear, 2NB01, could be energized for a functional test. Work had been performed on 2NB01 under MWO 29200907 to replace the existing GE supplied transformer core and coil assembly. A functional release permits the removal of clearance tags so that equipment can be tested prior to return to service. Based on the observation of the SSS at the clearance desk, the contractor foreman did not appear to understand fully his responsibility in requesting a functional release. At the time the functional release form was signed by the foreman, panels were still removed from 2NB01 and technicians were working inside the switchgear. The SSS became concerned when the foreman did not seem to understand the functional release process. The SSS then personally went to inspect 2NB01 where he discovered that work was still in progress. The SSS took immediate steps to stop the functional release until such time as work was completed on 2NB01. The SSS took action to stop the functional release prior to clearance tags being removed and equipment being energized. Although no personnel were injured, the possibility existed that injuries could have resulted from the foreman's actions. Maintenance management has subsequently taken action to ensure that sub-clearance holders are aware of their responsibility before requesting release of equipment for functional testing.

This is the second occurrence described in this report of an error in the clearance process. This is an area of continued concern since the proper implementation of this program is critical during a refueling outage.

No violations or deviations were identified.

5. Refueling Activities (60710)

a. General

The inspectors monitored refueling operations in the control room, the containment building, and the fuel handling building. The refueling activities at the beginning of the outage consisted of a complete core off-load. These activities were accomplished without major problems. Several delays were experienced due to tool operability problems, refueling machine (SIGMA) problems, and misplacement of fuel assemblies in the spent fuel pool. The licensee evaluated the misplaced fuel assemblies for criticality concerns and potential radiation concerns in rooms adjacent to the spent fuel pool. The licensee found that there was no potential for criticality with the fuel rack arrangement in the Unit 2 spent fuel pool. Also, the placement of the assemblies did not affect radiation levels in adjacent rooms.

b. Reactor Head Stud Dropped During Removal from Reactor Head

On March 16, the Unit 2 reactor vessel head studs were being removed from the vessel head by contractor personnel in preparation for the reactor head removal. One of the 54 studs had been removed and placed in a storage rack located on the floor of the reactor cavity. When the second stud was lowered into the rack it became hung up at an angle in the rack. The hoist operator, due to inattention, continued to lower the hoist hook and the vessel head stud tilted to one side. Enough slack was formed in the lifting strap that the strap became disconnected from the hoist hook and released the stud. The stud then fell to the reactor cavity floor, a distance of approximately five feet.

During the fall the stud struck the reactor head, a banana cover and the cavity liner resulting in small dents or scratches to all three. The banana cover provides a ventilation path from the below vessel area to the reactor cavity during normal operation. When the reactor cavity is flooded up during refueling, the banana covers are repositioned to act as seals to prevent water from draining from the reactor cavity. The damage to the banana cover will not prevent it from performing its sealing function, but it will have to be repaired or replaced prior to being returned to its ventilation function. The dent on the vessel head was evaluated and determined to be insignificant. The dented area on the vessel head was later buffed to a smooth finish by maintenance personnel. The dropped stud will be replaced due to thread damage. There were no personnel injuries as a result of this incident although several persons were in the area at the time. The cause of this incident was inattention to detail by personnel performing the stud removal evolution.

No violations or deviations were identified.

6. Management of Unit 2 Refueling Outage

Several events or delays experienced during recent Vogtle outages have been partially attributed to the lack of clear communication between management and working level personnel resulting in an inadequate understanding of management expectations. In an effort to ensure that plant management expectations are met during infrequently performed tests, or evolutions that have the potential to significantly degrade the plants margin of safety, the licensee has implemented a management standard for oversight of various tests or evolutions. These tests or evolutions include reactor startup, RCS draindown to reduced inventory, integrated ESFAS tests, reactor vessel head lifts, ILRT, refueling, establishing backfeed, and turbine overspeed testing. For each of these evolutions, a manager will be designated who has continuous responsibility for the oversight of the test or evolution. Prior to performing the test or evolution, the designated manager will brief the personnel involved. Some specific items included in these briefings are: the need for exercising caution and conservatism; the need for open communications; applications of lessons learned; the need to terminate the activity when unexpected conditions or plant behavior occurs; and where practicable a simulator or in-plant walk-through.

These controls have already been implemented for RCS draindown, refueling, and the establishing of backfeed. Management has also increased visibility in the plant during this outage. This has been exemplified in management walkdowns of the RCS level instrumentation and backfeed lineup, and safety walkdowns in containment. A management walkdown of RCS level instrumentation prior to draindown discovered several problems with the implementation of procedural guidance for assuring reactor coolant level measurement accuracy and reliability. These problems included, provisions for venting the RCS sightglass not being established in accordance with procedures and the three pressurizer safety valves were not being removed in accordance with a maintenance work order with the openings where the safety valves were removed not covered as described in the maintenance work order. Also the PEO standing watch at the sightglass in containment had not been adequately briefed on use of a gauge that was installed as an additional aid to determine that the RCS vent path was not blocked in any way. Although the actual accuracy of the RCS level instrumentation was not compromised by any of these problem areas, plant management continue to stress communication, procedural compliance, proper shift turnover and supervisor involvement in plant activities. The inspectors concluded that these management activities are having a positive effect by increasing sensitivity and awareness in the plant to these important activities.

No violations or deviations were identified.

7. Reliable Decay Heating Removal During Outages (TI 2515/113)

The purpose of the Temporary Instruction (TI) was to review licensee activities during reactor plant outages which have the potential for contributing significantly to a loss of capability to remove decay heat from the reactor. Inspection activities were broken down into those concerning decay heat removal systems and those regarding the supply and distribution of electric power to the decay heat removal system and supporting systems. It should be noted that during the current Vogtle Unit 2 refueling outage, the licensee, as part of their outage risk assessment, plans to maintain three out of the normal four (2 DGs and 2 RATs) onsite/offsite power sources available when fuel is in the vessel. Although mid-loop entry is not planned with the reactor fueled, procedure 12008-C, Mid-Loop Operations, requires that when operating with the RCS level below 191 feet elevation with fuel in the reactor vessel that either one D/G and two off-site AC sources or two D/Gs and one off-site source shall be operable to supply power to the 1E 4160V AC buses.

The inspector reviewed the following concerning decay heat removal systems:

a. During refueling outage 2R2 only one approved special test procedure or operation involving decay heat removal systems is scheduled to be conducted. The procedure, T-ENG-90-28, Recirculation Flow Test of RHR, Cross Train; is intended to verify that in Modes 5 and 6, either RHR pump can supply the cooling requirements of 3000 gpm when its associated discharge valve is closed and its total flow is directed to the opposite train cold legs. This special test will be conducted when the reactor is defueled. A Westinghouse Safety Evaluation, SECL 89-864, determined that it is acceptable to realign the RHR system in this configuration provided that sufficient flow is available to meet the TS surveillance 4.9.8.1 requirement of 3000 gpm. The inspector reviewed the procedure and the safety evaluation and considered them to be acceptable.

b. (1) The inspector reviewed those TS and procedures which ensure that forced circulation decay heat removal is maintained when required. The surveillance requirements of TS 4.4.1.4.1.1, Cold Shutdown - Loops Filled, and 4.4.1.4.2.1, Cold Shutdown - Loops Not Filled, in Mode 5, and TS 4.9.8.1, Residual Heat Removal and Coolant Circulation High Water Level, and 4.9.8.2, Refueling Operations, in Mode 6 require that at least one RHR train is verified in operation and circulating reactor coolant at a flow rate greater than or equal to 3000 gpm at least once per 12 hours. The 12-hour verification is recorded on Data Sheet 3 of Procedure 14000, Operations Shift and Daily Surveillance Logs, Modes 5 and 6. Procedures 12006-C and 12007-C, Unit Cooldown to Cold Shutdown, and Refueling Operations, respectively, state the same operability requirements as the TS identified above. Procedure 13011, Residual Heat Removal System provides the necessary instructions for placing the RHR system in standby readiness and in service for RCS cooldown.

(2) The inspector ensured that when natural circulation is used that required conditions are met and temperature monitoring is taking place. Emergency Operating Procedure, 19002-C, ES-0.2, Natural Circulation RCS Cooldown, provides actions to perform a natural circulation RCS cooldown and depressurization to cold shutdown and provides temperature monitoring requirements. Abnormal Operating Procedure, 18019-C, Loss of Residual Heat Removal, contains instructions on how to gravity drain the RWST to the RCS upon loss of RHR. The inspector had no concerns regarding the capability of the licensee to perform natural circulation cooldown with the use of existing plant procedures.

The inspector reviewed the following regarding the supply and distribution of electric power to the decay heat removal system and supporting systems.

c. During the 2R2 refueling outage a minimum of three out of four 1E 4160V power supplies will be available when there is fuel in the reactor vessel. Normally, each of the two 4160V 1E buses is powered from its own RAT or its dedicated diesel generator. The two RATs are capable of supplying either or both of the 1E 4160 buses. During 2R2 only the 2A DG is scheduled to be out of service while there is fuel in the reactor vessel. During that time its 1E 4160V bus will be supplied by the normal feed from the 2A RAT.

d. Each 125V dc 1E bus at Vogtle is equipped with two battery chargers and a battery bank to supply the bus. The battery chargers are normally both energized and share the bus load, but each charger is capable of independently supplying the bus. Thus, when a battery is removed from service for testing or maintenance, either of the two chargers can carry the bus load. In Modes 5 and 6, per TS 3.8.3.2, Onsite Power Distribution Shutdown, a minimum of one train of 125V dc switchgear and associated distribution equipment shall be energized from its associated battery bank. One train consists of two battery banks and their associated chargers and buses.

e. Each 1E 4160V bus is normally supplied by an off-site power source though its own RAT. Each RAT is capable of supplying both 1E 4160V buses simultaneously, if necessary. Procedure 13427, 4160V AC 1E Electrical Distribution System, describes the steps to be taken to supply one train of 1E 4160V bus from the opposite train RAT such that both 1E 4160V buses are manually connected to the same off-site power source.

   The licensee also has a procedure which allows backfeed through the main and unit auxiliary transformers to the 1E 4160V buses during modes 5 and 6. There are three possible configurations available for each unit. Any of the three configurations can be implemented using procedure 13417, Main and Unit Auxiliary Transformer Backfeed to the 13.8KV and 4160V buses. These non-standard electrical lineups were analyzed by the licensee in REA VG-0040 and were determined to be acceptable provided that certain load limitations are not exceeded. The "limitations" section of procedure 13417 describes those operating limitations.

f. The inspector reviewed procedures to determine if sufficient guidance is available to aid operators to manually control electric power systems when automatic control systems are disabled. Several procedures are available for this purpose. Procedure 13427 provides instructions on energizing a 4160V AC 1E bus from either its associated DG or from a RAT. Emergency Operating Procedures, 19100-C, ECA-0.0 Loss of All AC Power, gives direction on reestablishing electrical power and loading equipment onto a bus. Additionally, procedure 13038, Operation From Remote Shutdown Panels, Attachment B; provides instruction on starting and placing a DG on a dead bus from outside the control room. The inspector determined that the reviewed procedures were adequate to provide sufficient guidance to operators.

g. As stated previously, three out of four power sources to the 1E 4160V AC buses will be available during 2R2 whenever fuel is in the reactor vessel. Both trains of RHR will remain in service until the reactor is defueled and will be returned to service prior to fuel reload. Since three out of four power sources will be available the inspector did not have a concern regarding increased vulnerability because of reduced electric power sources.

h. The inspector determined that it is the licensee's practice to declare a DG inoperable when its field flashing source is removed from service During 2R2, battery and DG outages will occur simultaneously on the same train.

In conclusion, based on the information reviewed by the inspector on licensee practices for maintaining decay heat removal during outages, no concerns were identified.

No violations or deviations were identified.

8. Review of Corporate Engineering and Design Change Support (40703, 37828)

During this reporting period, the inspectors visited the Southern Nuclear Operating Company offices in Birmingham, Alabama. The primary focus of this visit was to review and evaluate the off-site support organization's responsibilities, authorities, and lines of communication in the design change process, and to review selected design changes.

The SNC organization is responsible for oversight of the design process in support of the Vogtle site. SNC oversees the processing and tracking of design development, reviews work authorizations to ensure work is on an approved work list, and ensures the appropriate design organization has been designated to perform the work. Southern Company Services and Bechtel perform most of the engineering work for SNC. SNC sets the priorities and holds the support organizations responsible for meeting assignments. Both Bechtel and SCS maintain a dedicated Vogtle support organization.

The SNC Vogtle project is progressing toward a goal of six month design windows in which all design resources will be committed to preparation of DCPs six months prior to an outage. This will allow more time to procure materials, walkdown the DCP, handle exceptions and budget time. The present design process has resulted in a less efficient use of time and resources and some DCPs being completed and sent to the site at the time they were to be implemented.

The inspectors also met with SCS Vogtle project management, reviewed their design change process and organization and toured their facilities. The SCS support organization supports the site by preparing design changes, responding to requests for engineering assistance, and reviewing MDDs and FCRs. The inspectors found that administrative controls were clear, the process was well understood and lines of communication were well established. The inspectors found particularly noteworthy the degree to which SCS is striving to enhance productivity and efficiency. This was particularly evident in the on-going conversion of Vogtle drawings to a CAD system, the cable configuration data system, and the storage and control of Vogtle documentation.

The inspectors also reviewed a sample of DCP and MDD documentation to verify these changes were processed in accordance with the established controls. This review included safety evaluations and other checklists prepared to support the DCP. The items reviewed are listed below:

DCP 92-V2N0052, Revise OPDT and OTDT Setpoints to Support the Vantage 5 Fuel Upgrade

DCP 91-V2N0112, Provide Separation for Power Fail, Alarm Fail and the Steam Generator Level Control Circuits

DCP 90-V2N0060, Replace Plant Vent Flow Transmitter

DCP 92-V2N0054, Delete RHR Suction Valve Autoclosure Interlock

DCP 92-V2N0125, AFW Steam Supply Gate Valve Elimination

DCP 92-V2N0044, Replacement of Non-1E Transformers

DCP 92-V2N0142, Revise MCC Logic for RHR (2HV-8804A,B) Discharge Valves

DCP 92-V2N0009, Replacement of Low Flow Indicating Switches in the ACCW System

MDD 89-V2M085, Replace Main Control Board Access Panel Fasteners

MDD 90-V1M110, A Condenser Hotwell Baffle Repair

MDD 90-V1M108, Replace Obsolete Position Transmitter 1ZT-7116, Model 3552

Several FCRs and FCR trending were also reviewed. The inspector noted that the majority of FCRs were not related to personnel errors or errors in design but to preferential type changes. From this information the inspectors concluded that this was an indicator that the DCP process was working.

The inspectors also reviewed a recent audit report of SCS Vogtle project activities (dated August 16, 1991) and interviewed the nuclear safety engineer. The nuclear safety engineer is responsible for independent review of DCPs. Overall, both the audit report and the safety engineer found that personnel were knowledgeable in their area of expertise and work was being accomplished in accordance with applicable procedures and acceptable technical practices. The inspectors reached the same conclusion from their review.

No violations or deviations were identified.

9. Review of Licensee Reports, Followup (90712) (92700) (92701) (92702)

The below listed Licensee Event Reports and followup items were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of description, verification of compliance the TS and regulatory requirements, corrective action taken, existence of potential generic problems, reporting requirements satisfied, and relative safety significance of each event.

a. (Open) Violation 50-424/91-30-01, Inadequate Procedures For Reducing Reactor Water Level

The inspector reviewed the licensee's response dated February 13, 1992. This violation occurred because the procedures utilized on October 26, 1991, did not contain steps or cautions to verify the lineup for the reactor water level instrumentation to be used during the drain down evolution or to verify the adequacy of vent paths prior to commencing the drain down.

Corrective actions included revising procedures 12000-C, Post Refueling Operations (Mode 6 to Mode 5); 12007-C, Refueling Operations (Mode 5 to Mode 6); and 12008-C, Mid-Loop Operations; to include a step and a RCS sightglass header checklist to be completed if the RCS is to be drained below 15% level as indicated on pressurizer cold calibrated level (LI-0462). Also, a step was added to verify that an adequate RCS vent path is open and unobstructed prior to beginning the draindown. The vent paths specified in the procedure are the pressurizer manway or one of three pressurizer safety valves.

Also a section was added to procedure 13005-1,2, Reactor Coolant System and Refueling Cavity Draining, to address draining the refueling cavity to the RWST using the RHR system. These instructions were previously in another procedure. The licensee has now consolidated draining instructions into one comprehensive procedure. This procedure also contains verifications to ensure an adequate RCS vent path is open and unobstructed, and includes the checklist to ensure the RCS sightglass header is properly aligned.

Additional procedure enhancements have also been incorporated in several procedures including the alignment and use of RCS reduced inventory level instrumentation, and administrative controls to reduce the potential that the operation of the reduced inventory level instrumentation might be adversely affected. These enhancements include designation of the Operations Manager as having full responsibility and authority for the oversight of the reduced inventory evolution, and a requirement to complete a briefing with appropriate personnel on management expectations prior to performing the evolution; cautions on flow rates during RCS pumpdown; periodic walkdowns of the RCS sightglass using a checklist; periodic checks of adequate RCS vent paths; ensuring the ERF computer is selected to the current mode and trending RHR pump parameters for early detection of possible RHR pump degradation; and checks for a pressure difference between the pressurizer and containment atmosphere by observation of a temporary pressure gauge.

The procedural changes described above appear to adequately respond to the causes of this violation. However, this item will remain open pending observation of licensee performance, and procedural performance and adequacy during the Unit 2 refueling outage (2R2).

Also as followup to licensee corrective action on RCS level instrumentation, the inspectors walked down the reactor vessel sightglass lineup in containment, verified adequate vent paths for level instrumentation, verified that the digital monitor for pressurizer vacuum measurement was operational, and verified that the sightglass watch in containment understood his responsibilities. All these items were satisfactory.

b. (Open) Violation 50-424/91-30-02, Failure To Verify Adequacy of Design and Establish Design Control

The inspector reviewed the licensee's response dated February 13, 1992. The root cause for the lack of an analysis or a work order for the installation of the HEPA filter was inadequate administrative controls. Procedure 47009-C, Operation and Use of Portable Ventilation Units, did not contain a requirement to obtain an analysis or to initiate a work order prior to allowing the connection of a portable HEPA filter to safety related equipment. The root cause for the operations attempt to use the reactor water level indicating sightglass, which had not been placed in service, was a combination of a missing clearance tag, the personnel involved not maintaining adequate awareness of the modification status of the sightglass, and the modification status system which was confusing and cumbersome.

Procedure 47009-C was revised to prohibit the attachment of a HEPA units suction or discharge trunk to permanent plant equipment unless an RER has been dispositioned approving the specific application and to prohibit the attachment of temporary ventilation systems to any primary system or equipment. The procedure revision also expanded the administrative controls on the use of ventilation units in other plant areas. Shift personnel involved in the event were disciplined and counseled regarding the need for additional emphasis in maintaining awareness of plant configuration status and for investigating problems noted during major evolutions.

A review of procedural controls and hardware associated with reduced RCS inventory was performed. In addition to the procedure enhancements noted in the corrective action for violation 50-424/90-30-01, two noteworthy hardware modifications will be made to reduce the potential that a single failure or inappropriate action could result in a common mode failure of level instrumentation during draindown evolutions. One modification will vent the RCS sightglass to atmosphere, instead of connecting it to the pressurizer, while venting the other level instrumentation through the pressurizer. This approach provides separate pressure references and will act as a preventive measure to prevent a common failure of all instruments. The second modification involves the installation of a pressurizer pressure gauge. This gauge will assist Operations in determining if a pressure difference exists between the pressurizer and the containment atmosphere. If a pressure difference exists there may not be adequate venting of the pressurizer. Pressure differences will also result in sightglass and CR level indicator disagreement. A case study emphasizing the lessons learned from the October 26, 1991, event was developed and presented during licensed operator requalification training. To address the weaknesses noted in the modification system procedure 50007-C, Engineering Review of Design Change Packages; and procedure 50008-C, DCP Implementation and Closure; were revised to increase the shift supervisor's awareness of modification status and to ensure that required procedure changes, drawing revisions, training and other possible restraints are known prior to a system being returned to service. These changes include only maintaining the RTS checklists for active DCPs in the modification log and requiring department heads of impacted departments to sign the RTS checklist in the CR once their required changes have been made. These changes should ensure that all changes are verified complete before a system is returned to service and that a completion status is known for DCPs in progress. The Operations staff has received training on these changes. To improve the operators knowledge of plant configuration status clearances during the Unit 2 refueling outage (2R2) will be filed by system. Also, LCO sheets have been prewritten for system outages. This will help in ensuring LCOs are properly recorded.

This item will remain open pending further verification of the effectiveness of corrective actions during the Unit 2 refueling outage.

c. (Closed) VIO 50-424,425/91-02-01, Failure to Perform Seismic Monitoring Surveillances.

(Closed) LER 50-424/91-001, Procedure Discrepancies Result in Inadequate Surveillance of Seismic Instrumentation

The licensee responded to the violation on April 8, 1991. The violation for failure to perform the surveillances resulted from inadequate procedures due to failing to incorporate seismic instrument nameplate designations correctly into all the applicable surveillance procedures. The licensee took corrective actions for the violation by entering an LCO for both units until the associated procedures were revised and the surveillance tests were reperformed. Procedures 24727-1, 24735-1, 24734-1, 24736-1 and 24737-1, Time History Accelerograph and SMA-3 Recorder ACOT and Channel Calibration, were revised to correct tag number discrepancies. The ACOT surveillances which were found in error were reperformed with satisfactory results except for accelerograph AXT-19903 located on a Unit 1 pressurizer support. Channel calibrations which were found in error were reperformed with satisfactory results. An engineering evaluation was performed which determined that data taken from other operable seismic instruments would be acceptable in lieu of data required from AXT-19903. The licensee initiated an MWO to repair AXT-19903. The instrument was replaced and calibrated. The licensee also performed bench calibrations of accelerometers AXT-19900, 19901, 19904, 19905, 19906, 19924, 19925, 19921, 19902 and switches AXSH-19920, 19923, 19921 and 19922. Three accelerometers were found defective and replaced (AXT-199904, AXT-19906, AXT-19903).

In addition, the licensee modified the seismic instrument calibration procedures to incorporate a tilt test. This was based on vendor recommendations made as a result of corrective actions from the LER. The licensee initially considered this omission as a failure to fully implement the TS channel calibration requirements. Further review determined that the channel calibration requirements were met.

No violations or deviations were identified.

10. Summary of Enforcement Conference and Proposed Imposition of Civil Penalty

In January 1990, the NRC Region II received information alleging that VEGP Unit 1 was intentionally placed in a condition prohibited by TS. In response to that information, the NRC initiated an investigation to determine the facts and circumstances of the alleged activity. Based on its investigation, which was completed on March 19, 1991, the Office of Investigations (OI) concluded that TS 3.4.1.4.2 was knowingly and intentionally violated in October 1988 by VEGP Operations Shift Supervisors (OI Case 2-90-001).

On June 3, 1991, the NRC issued a Notice of Enforcement and Demand for Information (EA-91-141) to GPC. The purpose of the Enforcement Conference was to obtain information to assist the NRC in reaching enforcement decisions regarding the apparent improper conduct of senior licensed personnel during an event which occurred at VEGP Unit 1 on October 12 and 13, 1988. The event in question involved the apparent willful violation of TS 3.4.1.4.2 when Unit 1 RMWST valves were opened to facilitate chemical cleaning of the RCS. The TS required these valves to be closed and secured in position while the plant was in Mode 5 with the reactor coolant loops not filled. GPC responded to the Demand for Information letter on August 28, 1991.

An Enforcement Conference was held in the Region II Office on September 19, 1991. Based on the information provided by GPC personnel, the NRC concluded that a willful violation of TS 3.4.1.4.2 did not occur although a violation of the TS did occur. On December 31, 1991, a Notice of Violation and Proposed Imposition of Civil Penalty - $100,000 was issued. The proposed violation resulted from the failure of GPC management to provide adequate procedures, appropriate training and guidance relative to mid-loop operation, and planning assistance to operations personnel at VEGP during the first refueling outage and associated chemical cleaning evolution that involved the injection of chemicals into the RCS. This item is identified as VIO 424/92-04-01: Failure of GPC Management to Provide Adequate Procedures, Appropriate Training and Guidance Relative to Mid-Loop Operation.

On January 30, 1992, GPC responded to the Notice of Violation and Proposed Imposition of Civil Penalty. Georgia Power denied the violation occurred and considers the civil penalty to be unwarranted.

11. Exit Meeting

The inspection scope and findings were summarized on March 20, 1992, with those persons indicated in paragraph 1. The inspector described the areas inspected and discussed in detail the inspection findings identified. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

12. Abbreviations

AC	Alternating Current
ACCW	Auxiliary Component Cooling Water System
ACOT	Analog Channel Operational Test
AFW	Auxiliary Feedwater System
ARV	Atmospheric Relief Valve
BFIV	Bypass Feedwater Isolation Valve
BOP	Balance of Plant
CAD	Computer Aided Drawing
CCW	Component Cooling Water System
CR	Control Room
CS	Containment Spray System
dc	Direct Current
DC	Deficiency Card
DCP	Design Change Package
DG	Diesel Generator
EOL	End of Life
ERF	Emergency Response Facility
ESFAS	Engineered Safety Features Actuation System
FCR	Field Change Request
[illegible]	General Electric Company
[illegible]	Georgia Power Company
[illegible]	High Efficiency Particulate Air Filter
[illegible]	Integrated Leak Rate Test
[illegible]	Justification For Continued Operation
KV	Kilovolt
LAN	Local Area Network
LCO	Limiting Conditions for Operations
LER	Licensee Event Reports

LLRT	Local Leak Rate Test
MCC	Motor Control Cubicle
MDD	Minor Departure From Design
MFIV	Main Feedwater Isolation Valve
MWO	Maintenance Work Order
NPF	Nuclear Power Facility
NRC	Nuclear Regulatory Commission
NSCW	Nuclear Service Cooling Water
OPDT	Over Pressure Delta Temperature
OTDT	Over Temperature Delta Temperature
PA	Protected Area
PEO	Plant Equipment Operator
PM	Preventive Maintenance
ppm	parts per million
RAT	Reserve Auxiliary Transformer
RCS	Reactor Coolant System
RER	Request for Engineering Review
Rev	Revision
RHR	Residual Heat Removal System
RO	Reactor Operator
RTD	Resistance Temperature Detector
RTS	Return to Service
RWST	Refueling Water Storage Tank
SCS	Southern Company Services
SFPC	Spent Fuel Pool Cooling System
SG	Steam Generator
SNC	Southern Nuclear Company
SSS	Shift Support Supervisor
TS	Technical Specification
UAT	Unit Auxiliary Transformer
USS	Unit Shift Superintendent
VEGP	Vogtle Electric Generating Plant
VIO	Violation