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

Report Nos.: 50-321/96-06 and 50-366/96-06

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

Docket Nos.: 50-321 and 50-366 License Nos.: DPR-57 and NPF-5

Facility Name: Hatch 1 and 2

Inspection Conducted: March 31, 1996 - May 11, 1996

Lead Inspector: E. Christnot For 6/10/96
B. L. Holbrook, Sr. Resident Inspector Date Signed

Other Inspectors: E. F. Christnot, Resident Inspector
R. P. Carrion, Project Engineer
J. L. Coley, Reactor Inspector
(Paragraphs 3.0.1 - 3.0.3, 3.3.1, 3.3.2)
P. J. Fillion, Reactor Inspector
(Paragraphs 4.5.1, 4.5.2, 4.6)
F. N. Wright, Radiation Protection Inspector
(Paragraphs 5.2 - 5.4)

Accompanying Inspector: James A. Canady

Approved by: P. H. Skinner 6/10/96
P. H. Skinner, Chief, Date Signed
Reactor Project Branch 2
Division of Reactor Projects

SUMMARY

Scope: Inspections were conducted by resident inspectors and regional inspectors in the areas of plant operations which included; Unit 1 general refueling and startup activities, review of the Mark I Hardened Vent Modifications, Unit 2 shutdown and startup following feedwater line repair, Unit 1 scram on high pressure, review of notifications for engineered safety feature actuations, and inspection of open items; maintenance which included, review of Unit 1 vessel internals and core shroud inspections, general maintenance activities, surveillance tests, and inspection of open items; engineering which included, Unit 1 suppression pool inspection, Unit 1 leaking fuel inspection, control rod scram time testing, leak rate tests, electrical modifications and inspection of open items; and plant support which included, routine activities, a Notice Of Unusual Event for a potentially contaminated injured individual transported offsite, external and internal exposure controls, control of radicactive material and

contamination, As Low As Reasonably Achievable program implementation, and control of transient fire loads.

The inspectors conducted back shift inspections on the following dates: April 1-4, 6-11, 13, 20, 24, 27, 28, and May 1-2, 1996.

Results: Five violations, two non-cited violations, two inspector followup items, and one unresolved item were identified.

Plant Operations:

The inspectors concluded that the Unit 1 startup, system testing and power uprate testing activities following refueling were well planned and controlled. Communications between engineering, operations and maintenance personnel were adequate. The pre-job briefs were routine and sufficiently detailed to reduce errors (paragraph 2.2).

The inspectors concluded a review of TI 2515/121, Verification of Mark I Hardened Vent Modifications (GL 89-16) which had been started in 1992. The inspectors verified a clear link existed between the emergency procedure flow charts and plant emergency procedures. The inspectors concluded procedural guidance and operator training were adequate to initiate emergency venting of Unit 1 and Unit 2 primary containment systems under accident conditions. Deficiencies were not identified and this issue was closed (paragraph 2.3).

During the Unit 2 startup following corrective maintenance for a small feed water line leak, the inspectors observed that; procedures were used, communications were satisfactory, and shift supervisory oversight was evident. Maintenance activities were conducted in accordance with procedures and were adequately controlled (paragraph 2.4).

The inspectors concluded from a review of the Unit 1 high pressure scram which occurred on April 30, that operators used procedures and communicated satisfactorily. Operations management provided adequate oversight during the scram recovery actions. Maintenance activities were conducted using procedures and engineering support was evident (paragraph 2.5).

A non-cited Violation (50-321/96-06-01: Delay In Making 10 CFR 50.72 Notification For An Engineered Safety Feature Actuation), was identified. The inspectors concluded that a delay in making an NRC notification for an engineered safety features actuation was due to deficiencies in operations personnel interpretation and understanding of the reporting requirements (paragraph 2.6).

Maintenance:

The inspectors concluded that plant maintenance involving the in-

vessel examination and repair activities of reactor vessel internals were conducted in accordance with applicable approved instructions by knowledgeable engineers and technicians (paragraph 3.0.1).

An Inspector Followup Item (50-321,366/96-06-02: Examination Of Tie Rod Nut Locking Devices), was identified. This concern was addressed by the inspector which related to the licensee's failure to document the engagement of tie rod nut locking devices in the nut slot with visual examination for the reactor vessel core shroud stabilizer assemblies. This oversight indicated improvements can be made in procedure requirements and in developing a more aggressive attitude for the examination and documentation of critical applications (paragraph 3.0.2).

Foreign material (a stove bolt) was discovered by the licensee in the reactor vessel. A washer was inadvertently dropped into the reactor vessel this outage, and was not retrieved. These are examples of foreign material exclusion concerns which should receive additional attention by the licensee to insure the integrity of the reactor vessel (paragraph 3.0.3).

A violation (50-321/96-06-03: Failure To Follow Procedure During Safety Related Valve Maintenance), was identified. The inspectors concluded that contractor work activities were not adequately controlled or documented. In this case the problem presented little safety significance. However, poor work practices, lack of control for maintenance activities, and inattention to detail demonstrated inadequate performance. This problem was significant because quality control hold points were bypassed, changes in job scope were not reviewed by quality control personnel, and procedurally required visual examinations for work on safety related components were not performed (paragraph 3.0.4).

The inspectors observed and reviewed Unit 1 surveillances during the unit startup activities and concluded Technical Specification requirements were met (paragraphs 3.1.1 - 3.1.3).

The inspectors observed that operator communications during a Unit 1 high pressure coolant injection surveillance were poor. Headset communications link from the control room to the local equipment required very loud communications. Three part communications were not consistent during the surveillance and at times non existent. A minor administrative error was observed during the activity (paragraph 3.1.4).

A Violation (50-321/96-06-04: Failure to Meet Technical Specification Surveillance Requirements Prior to Withdrawal of a Unit 1 Control Rod on Two Occasions, While in Cold Shutdown), was identified (paragraph 3.2).

A Violation (50-321, 366/96-06-05: Ineffective Corrective Actions

to Strengthen the Technical Specification Surveillance Program), was identified. Previous actions to correct surveillance performance deficiencies and strengthen the surveillance program were not fully effective, as evidenced by the continued poor performance in this area. The failure to effectively implement corrective actions to strengthen the surveillance program has resulted in two violations, two non-cited violations and five Licensee Event Reports in two years (paragraph 3.2).

Licensee corrective actions taken on previously identified inspection findings were thorough and well-documented with the exception of the area identified above (paragraphs 3.3.1, 3.3.2).

Engineering:

The inspectors concluded that the actions taken to inspect and clean the suppression pool were very good and management was actively involved. The inspectors concluded that the debris found in the suppression pool did not present a significant risk for emergency core cooling system suction strainer blockage (paragraph 4.1).

The inspectors observed that a root cause or failure mechanism of the Unit 1 leaking fuel was unable to be determined. The inspectors concluded that the sipping program for the failed fuel was thorough and exhibited good planning. The inspectors concluded that the previous testing had accurately identified the core areas where the fuel leakers were located (paragraph 4.2).

An Unresolved Item (50-321, 366/96-06-06: Review Of Scram Time Testing Methodology And Physics Review Prior To Single Control Rod Scram Time Testing), was identified. The inspectors will review licensee supplied documentation to determine the safety significance with respect to differences between the Unit 1 Technical Specifications and the Final Safety Analysis Report (paragraph 4.3).

A Non-cited Violation (50-321/96-06-07: Inadequate Test Procedure Resulting in Loss of Reactor Vessel Inventory for Unit 1), was identified. The procedure did not identify test limitations to account for varied system configurations during test activities. The inspectors concluded that improved work scheduling and coordination for simultaneous work activities may have also prevented the problem (paragraph 4.4).

Review of the emergency diesel generator (alternator) replacement indicated licensee's management commitment to resolving safety issues. First, the decision to replace the generator was conservative. Second, a significant amount of resources were expended in resolving the harmonic current issue, and actions will continue (paragraph 4.5.1).

A Violation (50-321, 366/96-06-08: Incorrect Set Points for Molded-Case Circuit Breakers), was identified. The violation was a concern because it revealed the lack of clear guidance from engineering for an activity that should have been covered by such guidance. Also, review of testing for newly installed molded-case breakers identified that the program was not concerned with verifying the instantaneous set point. This is identified as a weakness (paragraph 4.5.2).

An Inspector Followup Item (50-321/96-06-09: Review of Design Change Work Deficiencies and Licensee Corrective Actions), was identified. The inspectors were informed that a wiring error was found involving a modification to the Emergency Diesel Generator timers. Later the inspectors observed similar deficiencies during wiring activities for the Reactor Feedpump controls. The inspectors will conduct a more detailed review of design change work deficiencies to gain a better understanding of the problems and review licensee corrective actions (paragraph 4.5.4).

Plant Support:

The inspectors reviewed actions following the Notice Of Unusual Event for a potentially contaminated injured individual transported offsite on April 20. The inspectors concluded that licensee activities at the sitc and hospital were conducted in accordance with procedures. Overall radiological controls and supervisory oversight were good. The inspectors concluded that no regulatory requirements were violated. However, increased attention to personnel safety matters may reduce the possibility of similar problems (paragraph 5.1).

Based on interviews with licensee staff, record reviews, and observations made during tours of licensee facilities, the inspector found the Radiation Protection program to be adequately managed. Internal and external exposure control programs satisfactorily implemented with all radiation exposures within 10 CFR Part 20 limits. No concerns with individual radiation exposures were identified (paragraph 5.2).

A Violation (50-321/96-06-10: Failure to Maintain Records Showing the Results of Surveys Required by 20.1501), was identified. The licensee's control of low level radioactive contamination appeared to be a program weakness (Paragraph 5.3).

Weaknesses related to attention to detail in job planning were identified during the inspection (Paragraphs 5.3 and 5.4).

The inspectors concluded transient fire loads, flammable and combustible liquids were controlled in a satisfactory manner. The inspectors did not identify any deficiencies with respect to plant practices and the Fire Hazard Analysis (paragraph 5.5).

REPORT DETAILS

Acronyms used in this report are defined in paragraph 9.

1.0 Persons Contacted

Licensee Employees

*Anderson, J., Unit Superintendent
*Betsill, J., Operations Manager
Coggins, C., Engineering Support Manager
*Curtis, S., Operations Support Superintendent
*Davis, D., Plant Administration Manager
Fornel, P., Performance Team Manager
*Fraser, O., Safety Audit and Engineering Review Supervisor
*Hammonds, J., Regulatory Compliance Supervisor
*Kirkley, W., Health Physics and Chemistry Manager
*Lewis, J., Training and Emergency Preparedness Manager
*Moore, C., Assistant General Manager - Plant Support
*Roberts, P., Outages and Planning Manager
*Sumner, H., General Manager - Nuclear Plant
*Thompson, J., Nuclear Security Manager
*Tipps, S., Nuclear Safety and Compliance Manager
*Wells, P., Assistant General Manager - Operations

Other licensee employees contacted included office, operation, engineering, maintenance, chemistry/radiation, and corporate personnel.

Non Licensee Employees

Brossier, C., Site Manager, General Electric Company
Carter, C., Refuel Project Manager, General Electric Company
Port, J., Generator Field Engineer, General Electric Company

2.0 Plant Operations (60710) (71707) (71711) (92901)

Activities within the control room were routinely monitored. Observations included control room manning, access control, operator professionalism and attentiveness, and adherence to procedures. Instrument readings, recorder traces, annunciator alarms, operability of nuclear instrumentation and reactor protection system channels, availability of power sources, and operability of the SPDS were monitored. Control Room observations also included ECCS system lineups, containment and secondary containment integrity, reactor mode switch position, scram discharge volume valve positions, and rod movement controls.

Observed activities were conducted as required by the licensee's procedures. The complement of licensed personnel on each shift met or exceeded the minimum required TS. Observed operating parameters were verified to be within TS limits.

2.1 Plant Status

Unit 1 began the report period in day 8 of the 16th refueling outage. Unit startup began April 27. The unit scrammed from approximately 20% RTP on April 30, due to high reactor pressure caused by EHC problems. The EHC problems were resolved and the unit was restarted the same day. 100% RTP of the new 2558 MWT (power uprate) limit was reached on May 7. The unit ended the report period at 59% RTP on May 11, after a power reduction due to a problem with the RFP 1B discharge check valve.

Unit 2 began the report period at 100% RTP. The unit was shutdown on April 25, to repair a reactor feedwater vent line leak. Unit startup began on April 26, and 100% RTP was reached on April 29. The unit remained at this power level for the remainder of the report period with the exception of scheduled power reduction for routine testing.

2.2 Unit 1 General Refueling Activities and Startup After Refueling

The inspectors observed licensee activities during refueling, fuel debris inspection, blade guide replacement, and other invessel work activities. The inspectors reviewed applicable procedures to verify activities were conducted as required. Among the procedures reviewed were the following:

34FH-OPS-001-0S:	Fuel Movement Operations, Revision 13
42FH-ERP-014-0S:	Fuel Movement, Revision 12
10AC-MGR-021-0S:	Foreign Material Exclusion, Revision 0
51GM-MNT-002-0S:	Maintenance Housekeeping and Tool Control, Revision 11

The inspectors rode the refueling bridge to observe operator actions during fuel reload. The inspectors observed that SRO personnel were continuously present; provided oversight; and verified fuel moves were conducted correctly. Required refueling bridge communications with the control room were established and maintained.

The inspectors concluded that activities associated with fuel offload and reload were completed with no operator errors. This demonstrated continued improvement in operator performance since the previously inspector identified weakness concerning fuel movement errors. Managements efforts to correct and strengthen refueling errors were effective as evidenced by performing two refueling outages with no refueling errors.

Unit startup activities began on April 27, the reactor was brought critical on April 28, and the main generator was tied to the grid on May 2. This was about 8 days beyond the licensee's scheduled 33 day refueling outage.

The inspectors observed licensee performance during unit startup following refueling. The inspectors reviewed applicable startup, system operating, surveillance and power uprate testing procedures. The inspectors observed that onsite and offsite engineering personnel were present during the startup testing activities and provided oversight during power uprate testing.

The inspectors concluded that the unit startup, system testing and power uprate testing activities were well planned and controlled. Communications between engineering, operations and maintenance personnel were adequate. The pre-job briefs were routine and sufficiently detailed to minimize errors.

2.3 Review of Verification of Mark 1 Hardened Vent Modification - TI 2515/121

The hardened vent implementation was an element of the Mark I Containment Performance Improvement Program. The inspectors reviewed the TI and verified actions taken by the licensee were appropriate. The inspectors concentrated on TI section 04.04, review of plant emergency operating procedures and documents relating to post-accident use of the hardened vent. As part of the review the inspectors reviewed the following documents:

Procedure 31EO-EOP-101-1S: Emergency Containment Venting (Unit 1)
Procedure 31EO-EOP-101-2S: Emergency Containment Venting (Unit 2)
Procedure 31EO-EOP-012-1S (PC-1): Primary Containment Control Flow Chart (Unit 1)
Procedure 31EO-EOP-012-2S (PC-1): Primary Containment Control Flow Chart (Unit 2)

The inspectors verified that the EOP flow charts for both units directed actions, using applicable procedures, to emergency vent the drywell or suppression chamber before the suppression chamber pressure reached 54 psig for Unit 1 or 56 psig for Unit 2. The venting action was irrespective of offsite radioactivity release rate and, if necessary, defeating isolation interlocks.

The inspectors observed that the procedure for both units contained a note informing the user that the emergency vent path rupture disk, rupture setpoint was 51 psig. The procedure also directed the user to perform emergency venting only as necessary to maintain suppression chamber and or drywell pressure below 54 psig for Unit 1 or 56 psig for Unit 2.

The inspectors verified a clear link existed from the flow charts to the plant emergency procedures. The procedures appeared to be clear and concise with respect to required actions. The inspectors verified procedural guidance was available for defeating isolation interlocks to initiate the system under

accident conditions. The inspectors concluded procedural guidance was adequate to initiate actions to emergency ventilate Unit 1 and Unit 2 primary containment systems under accident conditions.

The inspectors met with training supervisory personnel to discuss training methodology conducted for operations personnel related to the hardened vent system. The inspectors observed that training was conducted for initial license training, license retraining and simulator training. The inspectors reviewed the following operator training documents to verify that the hardened vent system and its use were addressed in training:

LT-SG-50437-01:	License Training Simulator Guide
LT-LP-01301-02:	License Training Lesson Plan
LR-LP-20312-03:	31EO-EOP-101, Emergency Containment Venting
SO-IH-75207-01	(DCR 89-278 and 89-282, training for Unit 1 and Unit 2 Hardened Vent System)

The inspectors concluded the lesson plans adequately addressed the plant modifications. The material described the system; provided guidance on system use and initiation and presented a simplified diagram of flow paths and components. The inspectors reviewed the Unit 1 and Unit 2 Emergency Plan and did not identify any direct reference or link to the use of the hardened vent system.

The inspectors also reviewed P&ID H-16024, H-26084: Primary Containment Purge and Inerting System, for Unit 1 and Unit 2 respectfully. The inspectors verified the valve lineup required by plant procedures properly aligned a flow path to vent the primary containment.

The inspectors reviewed FSAR sections 5.2.3.8 and 6.2.5.2.4 for Unit 1 and Unit 2 respectfully. No discrepancies were identified.

Based upon this review and previous inspection activities documented in IRs 50-321, 366/92-22, 92-25, 93-05 and 93-06, TI 2515/121, Verification of Mark I Hardened Vent Modifications (GL 89-16), is closed.

2.4 Unit 2 Shutdown to Repair Small Feed Water Line Leak

On April 25, the licensee identified a small unisolable leak on a 3/4 inch FW vent line. The vent line was located on the common discharge header of the RFPs. The licensee determined the problem was a leaking socket weld. A shutdown was initiated to implement corrective maintenance.

Maintenance personnel stated the leak appeared to be caused by vibration. They also stated the line did not have a piping support and the socket weld was the anchor point. The licensee was evaluating the need to install a piping anchor.

The inspectors observed that procedures were used, communications were satisfactory, and shift supervisory oversight was evident. Maintenance activities were conducted in accordance with procedures and were adequately controlled. Unit startup began on April 26, and 100% RTP was reached on April 29.

2.5 Unit 1 Automatic Scram On High Reactor Pressure

On April 30, the unit was at about 20% RTP. One BPV was full open and a second BPV was open about 15% controlling reactor pressure. A significant EHC oil leak was identified on turbine control valve #1. A steam leak was also identified on a leakoff line for turbine stop valve # 4. In an effort to isolate the EHC leak for repairs, procedure 34SO-N32-001-1S: EHC Hydraulic System, was used to isolate EHC oil to all turbine valves except the BPVs. System drain valves were opened to relieve pressure on the isolated valves. The operators then observed that #1 BPV opened and closed quickly. EHC was then returned to the normal lineup.

The following day site management decided to again attempt to isolate the EHC system to all turbine valves except the BPVs and repair the leaks. Prior to isolating the valves, the B EHC pump compensator was adjusted to reduce the operating pump discharge pressure. The turbine valves were again isolated. System drain valves were opened to relieve pressure on the isolated valves. The system pressure appeared to stabilize. Operations then observed the standby EHC pump start and a short time later the BPVs closed. This resulted in a reactor scram on high pressure.

One of the inspectors reported to the control room to observe operator scram recovery actions. The inspector verified the unit was stable. ECCS systems did not actuate, and FW was used to control reactor vessel water level. All control rods inserted as required and all systems responded as expected. The inspector observed that SRVs A, D, and L indicated elevated temperatures. This was brought to operations management attention.

The inspectors were informed that the standby EHC pump automatically started as expected but system pressure was not increased rapidly enough to prevent the BPVs from closing. The inspectors observed that reactor pressure recorders displayed peak pressures at about 1080 psig. IR 50-321, 366/94-13 and 95-18, document other EHC system problems.

To correct EHC system pressure problems the B pump compensator and suction O-rings were replaced and the leak was repaired. The steam leakoff line on the #4 TSV was replaced to correct the steam leak.

The licensee initiated an ERT to review the scram, identify the root cause and make recommendations to prevent similar occurrences. Maintenance activities were completed and unit startup was initiated the same day. Reactor startup testing was resumed.

The ERT identified that between 1979 and 1988, the licensee completed DCRs to install valves necessary to isolate EHC to turbine valves for both units. Part of the modification was to allow online corrective maintenance of turbine valves while allowing operation of the turbine bypass valve system.

The inspectors reviewed a GE TIL which recommended two changes to the EHC system. One change involved the replacement of flared tube fittings with socket-welded tube fittings to decrease system leakage. The other change involved eliminating the FJS hydraulic pressure supply system. DCRs 77-80 and 79-182 were issued to implement the changes on Unit 1. DCR 77-80 was issued in two revisions. A letter from Bechtel Power Corporation, dated June 24, 1977, indicated that the changes were completed on Unit 1 and were also implemented on Unit 2. The first revision addressed implementing socket welds and did not mention the FJS system. The second revision, dated February 1, 1978, indicated completion of the TIL except modification to the FJS line. The revision indicated the FJS line was already deleted. It was not clear to the inspectors whether or not the FJS line was ever modified.

A third DCR, 83-173, was reviewed by the inspectors. This DCR was dated October 19, 1983, and involved the installation of two isolation valves in the FAS system for the turbine valves. This would allow maintenance on turbine valves and not affect bypass valve operation. Plant procedures were revised to provide instructions for isolation of the turbine valves using the two newly installed isolation valves in the FAS system.

As a result of the reviews and discussions with licensee personnel, the inspector concluded that, if the FJS hydraulic pressure supply system had not been modified as directed by the TIL, portions of the EHC system could depressurize when the EHC system was isolated from the turbine valves. Since this section of the procedure was implemented just before the reactor scram, it appeared to be a possible root cause. The ERT had not completed their investigation of DCR implementation as of the end of this inspection period.

During the scram recovery the inspectors observed procedures were used, communications were satisfactory and operations management provided oversight. Maintenance activities were conducted using procedures and engineering support was evident. Subsequent to the reactor scram, procedure 34SO-N32-001-1S: EHC Hydraulic System, was revised to prevent isolation of the turbine valves.

2.6 Late NRC Notification of Unit 1 ESF Actuation

On April 24, 1996, during the performance of the logic system functional test of the B loop of LPCI, the 1A EDG automatically started. The licensee determined that an undervoltage relay on the A 4160 VAC bus had failed. During the process of terminating the test procedure and restoring affected systems, to initiate corrective maintenance, the control switch for the 1A EDG was placed back in automatic. As a result the EDG automatically started at 2:40 a.m.

The onshift crew initially believed a relay failure caused the EDG to start and the problem was not reportable. Trouble shooting activities were conducted, corrective maintenance activities were completed, systems were verified to have operated correctly and the LSFT was later successfully completed. Following these activities and upon further review of the problem the licensee determined the problem was reportable.

10 CFR 50.72 paragraph (b) (2) (ii), Four-hour reports ESF Actuation, states in part that, the licensee shall notify the NRC as soon as practical and in all cases, within four hours of ... any event or condition that results in a manual or automatic actuation of any engineered safety feature ... The NRC was notified at 8:42 a.m. the same day. This was about two hours beyond the required reporting time.

The inspectors reviewed the licensee's performance with respect to 10 CFR 50.72 notifications and did not identify any deficiencies within the past two years. The inspectors concluded the delay was due to deficiencies in operations personnel interpretation and understanding of the reporting requirements. This delay in making a NRC notification constituted a violation of minor significance and is being treated as a NCV, consistent with Section IV of the NRC Enforcement Policy. This is identified as NCV 50-321/96-06-01: Delay in Making 10 CFR 50.72 Notification for ESF Actuation.

2.7 Inspection of Open Items

The following item was reviewed using licensee reports, inspections, record reviews, and discussions with licensee personnel, as appropriate:

(Closed) VIO 50-321, 366/94-17-01: Failure to Keep Records Documenting Remedial Training Performed and Failure to Document Activities Required by Training Department Procedures.

The inspectors reviewed the licensee's actions in response to the violation dated October 19, 1994. The licensee determined that the violation was the result of personnel oversight in not providing a training report documenting the remedial training. An additional contributing factor was management's interpretation of the procedure's requirements for the level of detail to be reported. Based on the inspectors review of the licensee's corrective actions, this violation is closed.

3.0 Maintenance (61701) (61726) (62703) (73753) (92701) (92702) (92902)

Maintenance activities were observed and reviewed during the reporting period to verify that work was performed by qualified personnel and that procedures adequately described work that was not within the skill of the trade. Activities, procedures, and work requests were examined to verify authorization to begin work, provisions for fire hazards, cleanliness, exposure control, proper return of equipment to service, and that limiting conditions for operation were met. The following maintenance activities were reviewed and witnessed in whole or in part:

3.0.1 Observation of Visual Examinations of Unit 1 Reactor Vessel Internals

Hatch Unit 1 is presently in the first outage, of the first period of the 3rd ISI interval. The inspector observed the ISI of in-vessel visual examination activities for the reactor vessel internals to verify that work was performed in accordance with TS, the 1989 Edition of Section XI to the ASME B&PV Code, correspondence between NRR and the licensee concerning relief requests, requirements imposed by NRC/industry initiatives, and other augmented inspection requirements required by NRC or recommended by GE in their SIL Nos. 552, 572, and 588.

Specific elements examined included: approved procedures were available and being followed, examination personnel were knowledgeable of the examination method, examination personnel with the proper level of qualification and certification were performing the various examination activities, examination results and evaluation of results were being recorded as specified in the ISI program and GPC's Visual NDE Procedure No. VT-H-750, Revision 7. Visual examinations of the following components were observed.

- ISI visual examination of the reactor vessel core shroud repair tension bar at the 45° vessel azimuth

- Core Spray Downcomer at the 350° vessel azimuth (including Welds 33, 34, and 35)

- Top Guide Hold Down Device at the 356° and 176° vessel azimuth

- Top Guide Aligner Pin Bracket and weld at the 0° and 180° vessel azimuth

- Core Spray Sparger T-Box at 170° vessel azimuth

- Reactor Vessel Core Shroud Vertical Beltline Welds V-5 at the 50° vessel azimuth and V-6 at the 230° vessel azimuth

Each of the above components was found to be free of cracks or other service degradation with the exception of vertical core shroud welds Nos. V-5 and V-6. The licensee found two indications on the OD of the shroud associated with weld V-5; one 12" long and one 2" long. The 12" indication is in a previously uninspected area. One 32" indication was also found on the shroud OD of weld V-6 with 18 inches of this indication in a previously inspected area. V-5 and V-6 were subsequently examined on the ID of the core shroud in accordance with the expansion plan and all eleven vertical welds were examined on the shroud OD. All visual weld inspections were conducted using enhanced VT-1 visual examination techniques in accordance with GE SIL 572. All inspections were completed in accordance with the latest published BWRVIP shroud inspection guidelines for repaired shrouds. Both V-5 and V-6 were verified by the inspector to have more than the minimum required ligament for continuing operation using existing BWRVIP criteria.

The inspector concluded that plant maintenance involving the in-vessel examination and repair activities of reactor vessel internals were conducted in accordance with applicable approved instructions by knowledgeable engineers and technicians.

3.0.2 Review of Unit 1 Core Shroud Tie Rod Re-Torque Activities

The inspector reviewed NRC's Supplemental SER for the Core Shroud Stabilizer Design, dated August 10, 1995, and GPC's Letter of Reply, dated February 20, 1996. The supplemental SER contained a provision for the licensee to resolve the issue of conformance with industry repair criteria prior to startup of Unit 1 after the Spring 1996, refueling outage and prior to implementation of the NRC approved Unit 1 Power Upgrade Program. The issue dealt with the industry position that, even if 360° through-wall weld failures were postulated to occur, no separation (and upward motion of a shroud section) would occur during normal operation. The licensee had calculated that a small gap of approximately 0.007 inch was projected at the H6B weld location during normal operation if a 360° through-wall crack scenario is postulated to

occur at the locations of welds H-2, H-3 and H-6. GPC stated that the calculated gap at H6B was the result of a loss of pre-load in the tie rods subsequent to a postulated failure of welds H-2 and H-3. GPC also stated that, the existence of the calculated gap had no adverse consequences on plant operation or performance as a result of design-basis accidents or transients.

The licensee analyzed the available options for preventing shroud horizontal weld separation during normal operating conditions and determined that the most desirable option was to increase the shroud stabilizer tie rod mechanical pre-load by applying additional torque to the tie rod nut. The additional torque was evaluated and the additional mechanical pre-load ensures that the industry repair criteria of no gaps during normal operation will be satisfied while maintaining allowable stress limits. The evaluations also included power uprate conditions.

On April 2, 1996, when GE technicians were verifying the existing tightness on the tie rod nut at the 315 degree azimuth in accordance with Paragraph 7.7 of GPC Procedure 17SP-022796-RZ-1-1S and GE's Field Disposition Instruction HT1-0194-12000, Revision 2, movement of the nut was observed. The clevis pin to clevis hook attachment had been visually examined prior to the tie rod nut tightness check, and no gap was indicated. This indicated that there was no large loss of pre-load. GE examined the entire assembly subsequent to the tie rod nut tightness check, and no abnormalities were identified. In addition, the three assemblies at 45°, 135° and 225° azimuth were examined and found to be tight, with no abnormalities identified.

GE concluded that the likely mechanism for the minor looseness of the nut in a single assembly was due to mechanical shakedown of the assembly. Due to debris, a burr or high spot, or a fitup not being quite flush, when the full thermal pre-load was applied at startup, the assembly shook down to a stable position under the increased load. Once unloaded, the result was minor looseness and, since the mechanical pre-load was very small by comparison to the thermal pre-load, GE considered this not to be a safety issue. Retorquing the tie rod nut will re-establish the design pre-load, which will be maintained since the assembly is now in a stable configuration under the pre-load configuration.

GE also concluded that based upon the assemblies at 45°, 135° and 225° being tight, material and design concerns can be discounted.

Questions concerning whether this mechanical shakedown phenomenon could occur on Unit 2 was addressed by GE and their evaluation concluded that the consequences would similarly not be a safety concern. In addition, since improved materials were used in the Unit 2 tie rod assembly, much higher mechanical pre-load values were obtained.

To assess whether the retorque of the tie rod nuts was conducted satisfactory, the inspector reviewed GPC's Shroud Re-Torque Procedure No. 17SP-022796-RZ-1-1S, Revision 0, Edition 1, examined video tape recordings of the initial and final visual inspection points for all four shroud stabilizer assemblies, and reviewed completed MWO 1-96-933: Re-Torque Shroud Tie Rod Assemblies (Design Change Request 95-065).

As a result of the above observations, reviews, and discussions with appropriate GPC, GE and SNC personnel, only one area of concern with this repair process was identified by the inspector. This concern dealt with the inspector's examination of in-vessel video tapes for the repair activities. These examinations revealed that only the tie rod assembly at 315° azimuth had video recorded the engagement of the retainer clip (locking device) into the nut slots for the retorqued tie rod nut. In addition, only partial engagement of the retainer clip into the nut slots was observed. Paragraph 9.11 of Procedure 17SP-022796-RZ-1-1S requires that GE and GPC-QC insure that the retainer engage one of the nut slots. Further investigation revealed that discrepancy reports had been issued by GE addressing only partial engagement of the retainer clips in the tie rod nuts for the stabilizer assemblies at the 45° and 225° azimuths. The discrepancy reports were evaluated by GE design engineers and their assessment was that the partial engagement was sufficient to assure that the tie rod nut was properly locked by the retainer. However, the inspector was concerned that this was an important installation verification that should have had a baseline inspection using VT-3 examination resolution and recorded on video; especially when considering the loss of mechanical pre-load experienced on the tie rod nut at the 315° azimuth this outage. The licensee was to conduct specified VT-3 inspections of accessible locking devices. When the upper spring assembly is removed to check the tie rod nut torque, the locking device is accessible. Procedure 17SP-022796-RZ-1-1S, paragraph 3.10 states that visual inspections using underwater cameras shall be recorded on video tape, but does not identify paragraph 9.11 as a VT-3 inspection. Discussions with cognizant GPC and SNC engineers revealed that the industry standard was a recent document that had just been received by GPC and when the work was performed they had considered the installation of the locking device only as part of the repair procedure. The engineers agreed they missed an excellent opportunity to obtain a baseline of the retainer to nut slot engagement. The GPC repair procedure required VT-3 examination of all other inspection areas required by the latest industry standard.

The licensee was to verify torque on one stabilizer tie rod nut next outage, and all others by the end of the specified inspection interval. Therefore, the inspector inquired as to whether a VT-3 inspection would be performed when the upper spring is removed for the tightness verification or would the

licensee allow the locking device to be made inaccessible by re-installation of the upper spring. The engineers stated that the process had not been finalized but that the industry standard would be implemented. In order to insure that this item is addressed again by the NRC, the inspector identified the issue as Inspector Followup Item No. 321, 366/96-06-02: VT-3 Examination of Tie Rod Nut Locking Devices.

The inspector concluded that improvement could be made in procedure requirements and a more aggressive attitude for the examination and documentation of critical applications.

3.0.3 Examination of Other In-vessel Work and Work Activities - Unit 1

Listed below are in-vessel work activity discrepancies identified during the refueling outage by the licensee, and verified by the inspector.

- Problems were encountered by the licensee achieving the proper alignment and flatness for the fuel support casing in the guide tube at control rod blade position 18-03. Subsequent adjustments were made by the licensee and the inspector verified by video tape recording that proper alignment and flatness were obtained.

- The inspector reviewed a video tape recording of a stove bolt wedged under the alignment tab of the control rod blade guide tube for Control Rod Blade 42-43. The bolt was approximately 6 to 8 inches long and 3/8 inch in diameter. The bolt had bent the left tab of the control rod blade guide tube up, but did not affect the alignment of the control rod blade. A GPC engineering evaluation for the associated deficiency card No. C09601615 was also reviewed by the inspector. The evaluation concluded that the bolt should remain undisturbed until such time as the licensee has cause to remove the control rod blade guide tube. The licensee's reasoning for this conclusion was: the bolt was large enough such that it would not be able to enter the lower tie plate of a fuel bundle and was not a threat to fuel integrity; the bolt seemed to be securely wedged and was not conducive to removal without significant control rod drive disassembly; the bolt could be moved from side to side (however, it could not be withdrawn from under the control rod blade guide tube tab); and if the bolt came loose from its current location, it was in a low flow area of the core and would not have the motive force to migrate to any other area.

- In addition to the above foreign material found in the reactor vessel, a worker dropped a speed wrench washer in the Unit 1 reactor vessel. The washer could not be found. Therefore, GE performed a lost-part analysis of the safety

and operational consequences for this discrepant condition. The analysis (GE-NE-T23-00700-15-37, Rev. 1) concluded that, the lost part did not present a safety or operation concern.

The above examples of foreign material exclusion discrepancies indicated the need for additional licensee attention.

3.0.4 Review of Unit 1 Valve Maintenance Activities

The inspectors reviewed and discussed with licensee personnel work activities performed on three valves 1B21F028D, MSIV Outboard Isolation, 1E41F006, HPCI Pump Outboard Discharge and 1E11F009, RHR Inboard Shutdown Cooling Suction. The work activities were performed by contract personnel and controlled by MWOs 1-96-1111, 1-96-0569, and 1-95-47 respectively. All valves were listed in the licensee ASME program.

The inspectors reviewed three applicable procedures involved with implementing and controlling ASME Section XI work activities. These included: 40AC-ENG-001-0S: ASME Section XI Program, Revision 8; 42EN-ENG-014-0S: ASME Section XI Repair / Replacement (R/R), Revision 8; and 50AC-MNT-001-0S: Maintenance Program, Revision 24. The inspectors also reviewed deficiency card C09601865, dated April 19, 1996, for licensee identified problems following the maintenance activities on the MSIV.

Several deficiencies were identified. Step 4.3 of procedure 42EN-ENG-014-0S required that all evaluated ASME section XI activities include review and signature by ANII and a QC specialist. In this case this was not done. A VT-3 examination was not conducted for bolting installed on the valve component during assembly. The job scope was expanded to include valve stem machining and oversized split rings were installed. The MWO was not updated as required by step 8.2.1.2 of procedure 50AC-MNT-001-0S. Additionally, the new work instructions added to the MWO were not reviewed by QC as required by step 8.2.4.1.

The inspectors reviewed an engineering evaluation document that assessed the above deficiencies for the MSIV. The evaluation documented that, even though the initial VT-3 examination identified as found problems and was recorded as unacceptable, a post maintenance VT-3 examination was not required by code. The deficiencies identified by the initial VT-3 examination and subsequent maintenance to correct the deficiencies did not meet the requirements to evoke the code required VT-3 examinations.

However, the inspectors observed that plant procedures, even though they were more restrictive than the code requirements, identified that these inspections and QC reviews be made.

The initial VT-3 examination of the HPCI valve identified several problems that required corrective maintenance. The examination was recorded as unsatisfactory in accordance with plant procedures. One maintenance activity required a post maintenance VT-3 examination by the ASME code. This meant that a post maintenance VT-3 examination be performed prior to returning the component to service. However, a post maintenance VT-3 examination was not performed prior to returning the component to service.

The inspectors discussed the HPCI valve problem with licensee personnel. The inspectors were informed that a contract QC inspector conducted a cleanliness inspection during valve assembly. The contractor, who was no longer at the site, was contacted by the licensee to discuss the problem. Although he was not assigned to perform a post maintenance VT-3 inspection, he informed the licensee he conducted a VT-3 inspection while performing his cleanliness inspection. The licensee determined his inspections was adequate for the code required post maintenance VT-3 inspection.

The inspectors reviewed an engineering evaluation document for the RHR valve deficiencies. The evaluation documented that the deficiencies identified by the initial VT-3 examination and subsequent corrective maintenance did not require a post maintenance examination per the code.

The inspectors discussed valve maintenance problems with licensee management. The inspectors were informed that these deficiencies did not meet managements expectations. However, the licensee concluded that all code requirements were met. The inspectors observed that similar problems were discovered and documented by SAER during the Unit 2 refueling outage in 1995. In this case the same problems occurred during maintenance on two RHR valves. The corrective actions for this problem was to develop a procedure revision to clarify procedure instructions. The inspectors review of plant procedures revealed that they contained instructions that should have prevented these problems.

The inspectors concluded from the reviews and discussions that the work activities involved with the valves were not adequately controlled and documented. The inspectors observed that the valves in question were successfully tested and met all acceptance requirements prior to unit startup. In this case the problem presented little safety significance. However, poor work practices, lack of control for maintenance activities, and inattention to detail demonstrated inadequate performance. The inspectors concluded that there were two possible root causes. The craftsmen performing the work did not properly communicate the change in job scope or work supervisors did not ensure the job scope changes were properly documented and reviewed.

The inspectors considered this problem as significant because QC hold points were bypassed, changes in job scope were not reviewed by QC, and procedure required VT-3 examinations for work on safety related components were not performed. This is identified as VIO 50-321/96-06-03: Failure to Follow Procedure During Safety Related Valve Maintenance.

3.1 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, authorization to begin work, data collection, independent verification where required, handling of deficiencies noted, and review of completed work. Witnessed tests were inspected to determine that procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and system restoration was completed. The following surveillances were reviewed and witnessed in whole or in part:

3.1.1 42SV-R42-009-0S: Combined Service-Performance and Modified Performance Test - Station Batteries

The inspectors observed two 18 month surveillances performed under this procedure. The test of the 1C EDG battery and the 1B SS battery. The results of the test of the 1C EDG battery indicated a 107.5 percent of required output. This test was completed and no deficiencies were identified.

The 1B SS battery test was attempted three times. The test output breaker tripped each time under a load of 1250 amps DC at the three to four minute interval of the five minute required duration. The tripping problem was corrected and the surveillance testing was successfully completed. The problem was related to the test breaker with no consequence to the SS battery. The inspectors reviewed Unit 1 FSAR section 8.5 with respect to these two items. No discrepancies were identified.

3.1.2 34SV-E11-001-1S: RHR Pump Operability

The inspectors observed SR 3.5.1.7 performance of the 1A and 1C RHR pumps. This activity was performed in accordance with the IST program. With both pumps operating in parallel the initial performance did not meet the pump delta psig requirement. System instruments were calibrated. The SR was again performed with acceptable results.

The inspectors reviewed Unit 1 FSAR sections 4.8, 6.4.4, and 7.4 with respect to this item. The inspectors observed that section 4.8 referenced the RHR steam condensing mode of operations. This mode of RHR was deleted during the Unit 1 refueling outage that began on March 23, and part of the equipment was removed.

3.1.3 34SV-E51-002-1S: Unit 1 RCIC Pump Operability.

During observation of unit startup activities, the inspectors observed performance of the RCIC pump operability test. The inspectors observed that the test was performed three times. During the first test, system flow and pressure requirements were not within the specified time requirement. Maintenance and engineering personnel conducted trouble shooting activities for the problem. Problems that could have caused the deficiencies were not identified. During the second test, system flow and pressure requirements were satisfactory. Following the second test, a review of test data revealed that there were differences between the tachometer and the control room speed indication. The tachometer was calibrated and a subsequent test was successfully performed.

The inspectors reviewed the test data results and verified TS and IST requirements were met. The inspectors concluded that the tests to verify system operability were successfully performed. System engineer and I&C personnel performance was good.

The inspectors reviewed FSAR section 4.7 with respect to this item and observed that the RHR Steam Condensing Mode of operations and RCIC steam inlet bypass valve, F119, were referenced. During the March, 1996, refueling outage the RHR steam condensing mode of operations was defeated and part of the equipment was removed. The F119 valve was also removed.

3.1.4 34SV-E41-002-1S: HPCI Pump Operability

On March 1, the inspectors observed the pump test to verify system operability. During the current outage, DCR 92-90 was completed to replace the system flow controller with a new digital controller. Part of the test was to verify operability and performance of the new controller. The inspectors observed that system response for automatic startup operation was acceptable. The controller functioned in manual and responded to various manual setpoint changes. Various setpoints were inserted, the system was placed in automatic and properly ramped in speed to the required setpoint. System operating characteristics were observed to be within the required procedural acceptance criteria. During the test new baseline data was obtained for IST requirements. The inspectors observed that operations personnel were cognitive of increasing suppression pool temperature that occurred during testing activities and took appropriate actions. The inspectors independently reviewed the completed test data and concluded all TS requirements were met. IST requirements were reviewed and determined to be acceptable.

The inspectors concluded that operations, engineering and maintenance performance was satisfactory. The system engineer was actively involved in the testing activity. Operations supervision provided adequate oversight.

Operations communications during the surveillance were poor. Headset communications link between the control room to the local equipment required very loud communications. Three part communications were not consistent throughout the surveillance and at times non existent. A minor administrative error was observed during the activity. The inspectors discussed these issues with operations supervision. The operator performing the test was cognitive of system parameters.

The inspectors reviewed FSAR section 10.4.7.2 and no discrepancies were identified.

3.2 Failure to Meet TS Surveillance Requirements Prior To Withdrawal of a Unit 1 Control Rod - In Cold Shutdown

The inspectors were informed by NSAC management that, on two occasions on April 21, 1996, during control rod withdrawal testing, operations personnel on Unit 1 withdrew a control rod and did not meet the TS requirements for withdrawal. Operations personnel identified the deficiency during a subsequent procedure review for control rod timing activity on April 26.

TS 3.10.4, Single Control Rod Withdrawal - Cold Shutdown, identifies several requirements prior to withdrawal of a control rod. One of the requirements was that section 3.9.5, Control Rod Operability - Refueling, be met. TS surveillance requirement 3.9.5.2 requires each withdrawn control rod scram accumulator pressure to be greater than or equal to 940 psig. Prior to the withdrawal of control rod 38-27 on April 21, accumulatpr pressure was not equal to or greater than 940 psig as required by TS.

The inspectors reviewed procedure 34GO-OPS-066--OS: Single Control Rod Withdrawal in Shutdown, Revision 4, Attachment 4, Accumulator Pressure, RPIS Response, and Withdrawal Time, that was used during the control rod testing activity. The procedure was used to document TS surveillance requirements and required specific data be recorded during this activity. Recorded data on attachment 4 indicated accumulator pressure for control rod 38-27 was 0 psig at 8:05 p.m., and 900 psig at 11:43 p.m. on April 21, when the control rod was withdrawn for testing. The inspectors observed that the control rod was inserted approximately 1 to 3 minutes later.

The inspectors observed that note 2, on attachment 4 of the data sheet, on the same page that control rod data was recorded, stated in part, to record accumulator pressure for each control rod that will be withdrawn prior to control rod withdrawal and

accumulator pressure must be equal to or greater than 940 psig. In this case the data was recorded; however, the operator recording the data and shift supervision failed to recognize the accumulator pressure was not within the required TS limits.

Operations management informed the inspectors that the operator involved with this problem stated that the procedure was confusing. The inspectors concluded that the procedure contained, in at least two separate locations, the necessary guidance to ensure the TS surveillance requirements were met. However, poor procedure wording may have contributed to the problem.

The inspectors discussed immediate and long term corrective actions with operations management. The licensee had recently increased emphasis for review of conditional or deferred surveillances. However, this problem was not discovered.

At the end of the inspection period, the inspectors were informed that no immediate corrective actions for this problem were implemented and long range corrective actions were still being considered. The inspectors concluded licensee actions for this problem was not timely. The failure to correctly complete the Technical Specification Surveillance requirement to withdraw a control rod while in Cold Shutdown was identified as VIO 50-321/96-06-04: Failure to Meet TS Surveillance Requirements Prior to Withdrawal of a Control Rod While in Cold Shutdown.

The inspectors discussed with operations management the continued poor performance with respect to the surveillance program implementation. Management acknowledged that deficiencies with respect to surveillance performance was a problem. Previous actions to correct surveillance performance deficiencies and strengthen the surveillance program were not effective, as evidenced by the continued poor performance in this area. Even though some root causes were different, similarities existed. Given the instances of TS surveillance deficiencies it was reasonable to have expected the licensee to have implemented necessary corrective actions to strengthen the TS surveillance program to prevent reoccurrence.

Although the inspectors viewed the discovery of this problem by operations personnel as positive, operator performance with respect to TS surveillances was viewed as a continuing problem. IR 50-321, 366/94-11, 94-28, 95-08, and 96-04 documented previous surveillance deficiencies and inspectors findings. At least five LERs, two NCVs and two violations associated with deficiencies and poor performance for surveillance program implementation were recorded within the past two years.

The failure to effectively implement actions to fully correct the surveillance program deficiencies was identified as VIO 50-321, 366/96-05: Ineffective Corrective Actions to Strengthen the Technical Specification Surveillance Program.

3.3 Inspection of Open Items

The Following items were reviewed using licensee reports, inspections, record reviews, and discussions with licensee personnel, as appropriate:

3.3.1 (Closed) VIO 50-366/95-21-01: Inadequate Control of Special Processes

GPC responded to this violation December 7, 1995. The inspector verified the licensee corrective action delineated in their response. This verification included: (1) reviewing documentation of the licensee investigation of the effects of painted reactor vessel surfaces on ultrasonic examination sensitivity when compared to the non-painted calibration blocks (the sensitivity differences had also been demonstrated to the Code Inspector); (2) review of documentation that the Code inspector had approved an alternate method of calibration utilizing separate calibration and examination cables; and (3) Procedure UT-HAT-702VO was revised to allow only a 2 decibel deviation in amplitude correction, in accordance with the ASME Code.

The inspector's review identified that the licensee had addressed the referenced discrepancies in a manner which will preclude their recurrence. This item is closed.

3.3.2 (Closed) URI 50-321, 366/94-25-01: Review of Previous Ultrasonic Examination Data

This issue addressed an issue in October, 1994, when an inspection of ultrasonic data for Weld No. 1B31-1RC-12BR-B-3 showed inconsistencies in the data recorded during different outages. These differences had not been documented and/or dispositioned. The licensee re-examined the weld and found the 1994 data to be in error. As a result of the finding, the licensee reviewed all their weld overlay data. This review revealed one other weld (No. 1B31-1RC-22AM-1) which showed significant differences in recorded data. The differences were that, until 1994 examination results showed indications at or near the examination volume, but not at the overlay interface. In 1994, no indications were recorded. The licensee re-examined this weld on April 4, 1996, and found that all of the data with

the exception of the 1994 data were in agreement. In addition, the licensee revised seven ultrasonic procedures to include a statement that an examiner will compare previous ultrasonic data with their examination results and disposition/document significant differences.

The inspector reviewed the previous examination and current re-examination data for Weld No. 1B31-1RC-22AM-1. In addition, the revisions made to Ultrasonic Procedures Nos. UT-H-400, UT-H-408, UT-H-409, UT-H-410, UT-H-419, UT-H-420, and UT-HAT-212VO were verified. The inspector considered the actions taken by the licensee to be satisfactory and this issue is considered closed.

4.0 Engineering Activities (37700) (37550) (37551) (37828) (92903)

On-site engineering activities were reviewed to determine their effectiveness in preventing, identifying and resolving safety issues, events and problems.

4.1 Unit 1 Suppression Pool Inspection, Cleaning And Coating

During the current refueling outage, the licensee continued their efforts to ensure suppression pool and ECCS suction strainer cleanliness. Their efforts included a diver swim through inspection, video taping of the underwater areas and components, sludge depth measurements, cleanliness and physical condition of the strainers, sludge and water sample analysis, and FME removal and documentation.

The inspectors reviewed BU 95-02: Unexpected Clogging of a Residual Heat Removal (RHR) Pump Strainer While Operating in Suppression Pool Cooling Mode, dated October 17, 1995, and observed licensee activities with respect to the bulletin. The inspectors also discussed the suppression pool cleanliness with contract divers and discussed the as found conditions with licensee management. IR 50-321,366/96-04 documented previous inspector observations for FME control in the suppression pool area. IR 50-321,366/95-23 documented suppression pool cleaning and inspection of Unit 2.

The divers inspection revealed that the strainers exhibited a fine dusting of sludge. However, all strainers were free of debris and obstructions. Sludge depths for bays 1 through 15 ranged from about 1/16 inch to about 1/4 inch. Parts of bay 16 contained about 1 inch of sludge. The sludge was removed from all bays.

Several pieces of debris was found and removed from the suppression pool area. The inspectors observed the debris items that were removed. The items included plastic tie wraps, pieces of duct tape, short pieces of rope, four nuts and a bolt, wrench, short lengths of tie wire, several small pieces of miscellaneous

paper, and several other miscellaneous items. Licensee management stated they believed part of the debris was due to work activities that occurred during equipment staging just prior to the inspection.

The inspectors reviewed FSAR section 4.0 and 6.0 and concluded the amount of debris identified for possible suction strainer blockage did not present a significant potential to render the ECCS inoperable due to insufficient NPSH. The FSAR NPSH calculations, for any particular ECCS, indicated adequate NPSH margin existed assuming one strainer 100% blocked and the second strainer 50% blocked. The inspectors review of the FSAR did not identify discrepancies between the FSAR and plant practices and procedures.

The inspectors concluded the licensee actions taken to inspect and clean the suppression pool were good and management was actively involved. The inspectors concluded that the debris found in the suppression pool did not present a significant risk for ECCS suction strainer blockage.

4.2 Unit 1 Leaking Fuel Inspection

Tests performed in March and August 1995 had identified cells in two distant areas of the core that contained suspected leaking fuel. IRs 50-321, 366/95-06 and 95-18 respectively discuss the details associated with these tests. Licensee sipping activities during Unit 1 Refueling Outage 16 found a leaking fuel bundle in each of the two separate areas identified by the earlier testing. A GE fuel inspection team confirmed that these bundles had failed fuel pins.

Leaking fuel bundle LYZ612, located at 27-14, was a second cycle bundle (reload 14) and its defects included two 4 inch secondary hydride splits around the 15 inch elevation. No debris was found and no fretting marks were observed. The second fuel leaker, bundle LYZ612 located at 25-28 was a third cycle bundle (reload 13). The defects of this bundle were a 25 inch split starting at the 15 inch elevation; two 6 inch splits around the 70 inch elevation. No fretting marks were observed for this bundle. One small piece of insignificant debris was found away from the defective fuel rod.

The licensee concluded from the size and the amount of debris, that there does not appear to be a new widespread intrusion event as occurred in cycle 10 of Hatch Unit 2. IR 50-321, 366/94-08 contains details associated with the Unit 2 debris intrusion event.

GE and the licensee were not able to determine the root cause or failure mechanism of leaking fuel. The sipping program to identify failed fuel was thorough and exhibited good planning.

The testing accurately identified the core areas where the fuel leakers were located.

4.3 Review of Unit 1 Control Rod Scram Time Testing

Unit 1 TS 3.1.4, Control Rod Scram Times, specifies requirements for control rod operability based upon scram times. SR 3.1.4.1 specifies that each control rod scram time to be within the limits of table 3.1.4-1 with reactor steam dome pressure greater than or equal to 800 psig. This requirement is to be verified prior to exceeding 40% RTP after fuel movement within the reactor pressure vessel.

The inspectors observed part of the activities and reviewed licensee documentation for the required test. The inspectors verified that scram times met the requirements of TS table 3.1.4-1. The inspectors confirmed the test were conducted prior to exceeding 40% RTP and reactor steam dome pressure was greater than 800 psig.

The inspectors reviewed Unit 1 FSAR section 3.4 with respect to the scram time test. The inspectors observed that the FSAR stated in part that the CRD system, with accumulators, provides the following average scram performance at any reactor pressure. The table presented information for 5%, 20%, 50%, and 90% of full control rod stroke. Additionally, stroke in inches for the various percentages as well as the required time for movement in seconds was presented.

The inspectors reviewed Unit 1 TS table 3.1.4-1, Control Rod Scram Times. The table indicated control rods were to be tested with respect to scram times for four different notch positions of each control rod. The TS did not address average scram times as referenced in the FSAR. The inspectors observed that there was no direct correlation with respect to control rod positions referenced in the FSAR and TS. The inspectors observed that licensee scram time data included average scram time for the control rod notch positions but there were no requirement to verify the recorded average scram times met the FSAR requirements.

The inspectors discussed this observation with reactor engineering personnel and licensee management. Management stated they would review the problem and provide documentation and evaluations that had been generated during the review and implementation process of the new improved TS. The inspectors will review the documentation to determine the safety significance when available.

Also, as part of the FSAR review, the inspectors observed that section 7.2.5, Inspection and Testing of RPS, discussed single rod scram test using the toggle switches on the protection system

operations panel. This test met TS SR 3.1.4.2 for a representative sample of control rods at a frequency of 120 days cumulative operation in Mode 1. The FSAR stated in part that, "prior to the test, a physics review is conducted to assure that the rod pattern during scram testing does not create a rod of excessive reactivity worth".

The inspectors discussed the statement with reactor engineering personnel to gain insight on how the physics review was conducted. The inspectors were informed that reactor power changes were evaluated and taken into consideration prior to single rod scram testing. However, the review was not a formal proceduralized process. Site reactor engineering contacted corporate engineering to discuss the FSAR statement. The inspectors were later informed that the licensee planned to proceduralize the physics review process. The inspectors will review procedures developed to conduct a physics review prior to single control rod scram time testing.

The inspectors will also review licensee supplied documentation to determine if any safety significance exists with respect to the TS and FSAR differences. These two items were identified as URI 50-321, 366/96-06-06: Review Of Scram Time Testing Methodology And Physics Review Prior To Single Control Rod Scram Time Testing.

4.4 LLRT Results in Unit 1 Loss of Vessel Inventory

On April 17, a loss of water from the Unit 1 reactor vessel occurred during LLRT activities. The test involved an air leak test of the SRVs 1G and 1F. Procedure 42SV-TET-001-1S: Primary Containment Periodic Type B and C Leakage Tests, Revision 15, required the installation of jumpers to actuate the SRV air valves. The SRVs did not open upon installation of the jumpers because the SRV air system was not pressurized. At the time that the jumpers were being installed reactor water level was at the vessel flange. The main steam line plugs were being removed. Once the main steam line plugs were removed the main steam lines flooded with water up to the closed MSIVs. When the air systems for both the SRVs were pressurized per the LLRT procedure they opened and 72 inches of water drained from the vessel through the open SRVs to the suppression pool. This equated to about 25,000 gallons.

The inspectors reviewed operator logs, procedures, drawings, attended licensee event review meetings, and discussed the event with licensee personnel. The inspectors determined that when the steam line plugs were removed pressure from the water in the steam lines was applied to the SRVs main piston. The inspectors observed from drawings that as the SRV air systems for the 1G and 1F SRVs were pressurized the air operated pilot valves would gradually open. This allowed pressure to be vented from the main

piston of the SRVs. As a result the SRVs main discs opened and the vessel draindown began.

During the inspectors discussions with licensee management, the inspectors were informed that licensee personnel could not understand why the SRVs opened when only 72 inches of the water pressure was applied across the SRVs main piston. The inspectors were also informed that, according to licensee training personnel, the main piston had a spring that prevented the SRVs from opening unless there was at least 50 psi across the main piston.

The licensee conducted additional reviews to fully understand the problem. They determined that the water pressure applied across the main pistons was approximately 50 feet of water and not six feet. This was a result of taking into account the actual SRV elevations in relationship to the main steam nozzles. The pressure applied across the main pistons was approximately 23 psi.

It was also determined that the 50 psi across the SRV main piston was a maximum pressure and not a minimum pressure as previously believed by licensee personnel. The SRVs are designed to open at some pressure less than 50 psi.

Previously, the SRV LLRTs were performed with the main steam lines dry. However, the procedure in use during this problem did not specify that the main steam lines be dry and did not identify any limitations for the performance of the LLRT.

Engineering personnel informed the inspectors that, due to the relative small pressures involved and the operation of an SRV, no damage to the SRVs was suspected.

The inspectors concluded that the event was quickly recognized by the control room operators. They were well aware of ongoing work and LLRT activities associated with the SRVs. They quickly realized why the reactor vessel drain down occurred and took immediate corrective actions to terminate the LLRT activities. However, the reactor water level draindown was terminated when level decreased to the bottom of the main steam line nozzles. The inspectors concluded the draindown problem did not present a significant safety concern. The loss of inventory was self limiting to the elevation of the steam nozzles.

The inspectors concluded that some licensee personnel did not have a thorough knowledge of the technical aspects of SRV operation. Training deficiencies for specific knowledge items, such as required pressure for SRV operation, was a contributing factor.

The procedure for performing the LLRT was not adequate. It did not identify test limitations to account for varied system configurations during the LLRT activity. The inspectors concluded that improved work scheduling and coordination for simultaneous work activities may have prevented this problem. The inadequate procedure constitutes a violation of minor significance and is being treated as a NCV, consistent with Section IV of the NRC Enforcement Policy. This item was identified as NCV 50-321/96-06-07: Less Than Fully Adequate Test Procedure Results in Loss of Reactor Vessel Inventory.

4.5 Modifications

The inspectors continued to review and observe the ongoing modification activities. The inspectors reviewed DCR and MDC packages and observed implementation activities. These reviews included 10 CFR 50.59 review, unreviewed safety question criteria, required testing and job task activities. The observed work included work process procedures, installation activities and required testing activities. Among the DCRs reviewed and installation activities observed were:

DCR 94-041: Power Uprate, Setpoint Changes
DCR 94-040: Power Uprate, Meters and Scales
DCR 94-044: TSI Abatement and Electrical Cables
DCR 94-048: Lower ATWS Recirculating Pump Trip
DCR 91-069: Rod Sequence Control System Removal
DCR 93-057: EHC Two-out-of-Three Trip Logic
DCR 94-022: Replace Turbine Generator Pressure Regulator

The inspectors verified that the 10 CFR 50.59 safety evaluations were adequate, verified that the modifications were reviewed and approved in accordance with the licensee's procedural requirements, that applicable design bases were considered, and that appropriate post-modification testing requirements were specified. The reviews completed by the inspectors did not identify any deficiencies.

4.5.1 DCR 1H95-17, Replace Electric Generator for EDG 1A.

Due to insulation degradation at the end turns, the original electric generator for EDG 1A was replaced with a new generator. During initial test runs, the new generator experienced tripping due to operation of the reverse power relay. As part of the trouble shooting for these trips, monitoring equipment was connected to analyze the voltage and current waveform at the generator leads. The voltage waveform was good, having relatively little harmonic distortion. The current waveforms; however, exhibited significant harmonic distortion. The 4063 kVA rated generator was producing about 550 kW, and the total harmonic distortion in the currents was 10, 17, and 8 percent on phases A, B and C respectively, (total harmonic distortion is the

square root of the sum of the squares of each of the harmonic amplitudes expressed as a percentage of the fundamental). The monitoring equipment (Dranetz) could display the magnitude of each harmonic present and the total harmonic distortion. The predominant harmonics were the third, fifth and seventh.

Not having any baseline data on system harmonics, the engineers thought that the new generator could be producing the harmonics, even though the voltage waveform was good. It was thought that perhaps some defect in the windings could be causing the generator to produce harmonics. Over the period of about a week, various tests were performed on the windings to investigate potential defects. These tests included:

* Checking that each coil was in the proper slot with an instrument called a Tic Tracer, which is basically a voltage sensor.

* Checking each coil with a surge tester, where the response of a coil to a surge is compared with the typical response.

These tests did not indicate any problems with the windings. At that point, EDG 1B was scheduled for a surveillance test (one-hour run). The monitoring equipment was installed on the output of EDG 1B during the run. At low loads, current waveforms almost identical to the EDG 1A waveforms were recorded. At higher loads, the total harmonic distortion was greatly reduced. The licensee then concluded that the harmonics were not being produced by the generators, but rather were present on the system. Acceptable test runs were carried out. The EDGs, including the new 1A, were declared operable.

The following week, a Region II inspector reviewed this situation as part of a routine inspection. The inspector interviewed the cognizant system engineers and design engineers concerning their rationale for resolving the problem, and reviewed the Dranetz printouts. The inspector discussed the trouble shooting with the Generator Field Engineer from GE who happened to be onsite for work on the main generator and was enlisted to work on the diesel generator issue. The inspector discussed concepts involving harmonics and synchronous generators with an engineer at the manufacturing location (Louis-Allis, Milwaukee, WI). Also, the inspector witnessed the measurement of harmonics on the 230 kV and 4.16 kV systems without any diesel generators running.

The inspector agreed with the licensee's conclusion that the EDGs were not producing harmonic currents beyond the standard acceptable level. Harmonics were present on the system because they were generated by solid state equipment, induction motors and single phase loads. The magnitude of harmonic currents (in Amperes) measured without the generators running were the same order of magnitude as those measured with the generator running

in parallel with the system. Harmonic currents tend to flow into a synchronous machine and the energy is dissipated as heat in the machine. This concept explains why the distortion was relatively high at low EDG loading and diminished at higher loading. This concept was confirmed by the manufacturer's engineer and the Transmission System engineers. The licensee stated that the plan for resolving the issue would include the following items:

* Consideration of whether it would be beneficial to examine the coils of the old EDG 1A to look for evidence of overheating, which may have been caused by system harmonic currents. The degradation at the end turns was caused by magnetic forces generated during starting and possibly out of phase paralleling.

* The level of harmonics would be measured during the loss of offsite power surveillance to be conducted on each EDG during the outage. This would give information about the harmonics on the system when the EDG was operating in isochronous mode isolated from the offsite power system. Once the measurements were obtained, engineering would evaluate their effect on system operation.

* As other EDG operability runs are performed, the level of harmonics on the system will be measured immediately before the surveillance test and during the test. Results would be evaluated by engineering.

* It will be verified that the operating procedures call for sufficient checking of stator resistant temperature detectors to ensure that excess heating due to the energy of harmonic currents is not taking place.

4.5.2 DCR 1H95-32, Coordination Enhancements.

As a result of previous NRC findings in the area of coordination, the licensee performed studies of coordination on the low-voltage systems. These studies led to the development of plant modifications to enhance the overall system coordination. DCR 1H95-32 was one of these modifications. It included replacement of molded-case circuit breakers, fuses and installation of new cables for ampacity considerations. The coordination studies themselves had been reviewed during previous inspections. During this inspection, the inspector reviewed the testing performed on new circuit breakers installed in the plant to ensure that the breakers performed as designed. Installation, setup, and testing of the circuit breakers was to be in accordance with maintenance Procedure 52PM-R24-001-0S, Allis Chalmers Low-Voltage MCC Inspection. The inspector noted that this procedure specified an

adequate test of the breaker thermal element. The procedure specified a functional test of the instantaneous element, but did not specify checking that the instantaneous element will operate in the correct range.

NRC Information Notice 92-51, Supplement 1, Misapplication and Inadequate Testing of Molded-Case Circuit Breakers, expresses the NRC's concerns with regard to the importance of verifying the set point of the instantaneous element of molded-case circuit breakers. Verification tests conducted at the factory or other offsite location would be an acceptable substitute for onsite test. Therefore, the inspector inquired whether such test had been conducted as part of the procurement process. The licensee responded that they did not specify such test, and did not determine during the inspection period whether the test had been performed. The licensee's approach to verifying the set point of the instantaneous element was not responsive to concerns expressed in the Information Notice. The inspector identified this as a weakness in the modification/maintenance program.

Step 7.4.11 of 52PM-R24-001-0S specified criteria for ensuring that breaker trip set points were properly adjusted. The step applies to magnetic-only circuit breakers used on motor feeder circuits. This step specifies an upper bound of 13 times motor rated FLC. The factor of 13 is in accordance with good industry practice. It is derived by multiplying three factors: starting current is usually not more than 6.5 times FLC, the theoretical maximum DC offset is 1.73 times starting current and the actual voltage at the motor terminals could be 1.1 times motor rated voltage (which increases the starting current). The inspector noted that this procedure step was weak in that it implied that 13 times was an upper limit rather than a good lower limit. No lower limit was specified.

The inspector followed up this comment on step 7.4.11 by checking the set point for four breakers selected at random. The inspection was made at MCC-1C in the diesel generator building, and the results of this inspection are summarized below.

Compartment	Load	FLC	Set Point (Amperes)/Multiple
1B	MOV-PSW to Turbine Bldg	3.3	100 / 30x
4B	MOV-PSW to Reactor Bldg	2.2	22 / 10x
6E	MOV-PSW to EDG 1C, DIV II	2.2	14 / 6.4x
7F	Fuel Oil Pump - EDG 1C	4.6	35 / 7.6x

The FLCs given in the table above were obtained from Motor Control Center Equipment List B-13059. This drawing did not specify the set point. The set point at compartment 1B was 30 times FLC (which was more than the value of 13 given in the procedure), and, therefore, did not meet the criterion of step

7.4.11. The other three settings met the criterion of step 7.4.11, but were set too low in light of the design considerations given above. The inspector requested a copy of the design guidance for breaker set points. The licensee did not produce any formal design guidance. They stated (verbally) that the current guidance (since 1989) was 13 times FLC or 2 times starting current, whichever is lower. The licensee stated that the original guidance, to which most of the breakers were set, keyed the set point to the cable ampacity. The inspector concluded that the original guidance was incorrect in that it did not address all the relevant design considerations of starting current, DC offset and voltage range. The licensee stated that they reviewed the maintenance history for the particular loads in the table above, and found no problems with tripping. The licensee stated that inadvertent breaker tripping has not been a problem at the site. The inspector stated that, in light of the finding, the set points were a concern because it appeared that all uncertainties were not resolved in favor of motors having the capability to complete their safety function when called upon.

The failure to provide documented inspections that included all relevant design considerations is a violation of NRC requirements. Activities affecting quality such as the setting of circuit breaker trip points shall be prescribed by documented drawings or instruction appropriate to the circumstances. The licensee could not produce any documented drawing or instruction covering set points as described above. Statements by the licensee indicated that the original instructions whether documented or not were inappropriate, and they led to the inadequate set points identified by the inspector. Also, the finding was applicable to set points for magnetic only breakers in general. Maintenance Procedure 52PM-R24-001-0S covered the set points in question, but was worded such that unacceptable settings would be perpetuated. The inspector noted that the FLC of loads on Drawing B-13059, sheet 6, had been revised in 1989. This represented an opportunity to identify the problem with the set points. This failure was identified as Violation 50-321, 366/96-06-08: Incorrect Set Points for Molded-Case Circuit Breakers.

4.5.3 Review of Valve Operator Separation During LLRT Testing.

On April 19, an LLRT on accumulator 1P52A015, for valve 1T48-F311, in the Containment Purge and Vent System was conducted. The test was conducted in response to GL 88-14, to verify the accumulators were capable of holding their valves closed for a minimum of 10 minutes. Two leaks were found on the accumulator. One of the leaks was between the actuator and the air cylinder housing the spring and the other leak was at the end fitting on the piston side. Therefore, corrective maintenance and re-LLRT was required.

Following an understanding that contract personnel repaired the leaks, a verification that the system was ready for the retest was needed. On April 21, the system was being pressurized to the required test pressure of 80 - 108 psig, to verify that previous leaks were repaired and that no additional leaks existed. While applying an increasing pressure on the system, the air cylinder, that weighs about 50 lbs, separated from the threaded area and flew about 20 feet across the top of the torus area. The cylinder hit a plant service water line and duct work. The cylinder then rested on top of the torus. Licensee's personnel assessed that there was no damage to plant service water line or duct work. No personnel injuries occurred.

On April 22, 1996, a retest was successfully completed. The licensee initiated an investigation into the problem. Their initial assessment indicated that worn parts (cylinder thread connections) caused the problem. The licensee was evaluating actions to take to identify worn threads for similar valve actuators. Additional recommendations included replacement of the valves and actuators.

The inspectors reviewed the applicable procedures and determined that the procedure provided adequate instructions to conduct the test. The procedure provided instructions to inspect all parts for physical damage and excessive wear. The valve vendor manual provided instructions to thoroughly inspect all parts and pay particular attention to threads, and other areas that provided sealing surfaces. The inspectors viewed the cylinder and threaded connection. The inspectors observed that, even after the actuator had separated from the valve, it was difficult to observe significant thread damage. However, some thread wear and smoothness of threads were observed. The inspectors did not identify that poor work practices were involved with the separation of the actuator from the valve. However, the procedure could be enhanced to provide a more exact method to identify potentially worn threads.

4.5.4 DCR Implementation Deficiencies

The inspectors were informed that a wiring error was found involving a DCR modification to the EDG timers. The error was made when personnel did not have guidance in the proper installation of HFA relays. The relay terminals were not numbered and the personnel assumed a numbering sequence that was erroneous. The error was discovered during post modification testing.

During the inspectors observations of wiring activities for DCR 90-165, for the RFPT Controls, the inspectors observed that the relays were in the process of being wired incorrectly. This error was similar to problem with the EDG timers. The inspectors contacted licensee personnel and the wiring was corrected. The

inspectors will conduct a more detailed review of DCR work deficiencies to gain a better understanding of the problems and review licensee corrective actions. This item was identified as IFI 50-321/96-06-09: Review of DCR Work Deficiencies and Licensee Corrective Actions.

4.5.5 Review of Omega Seal Installation On Unit 1 RWCU Heat Exchanger

The inspectors reviewed DCR 90-45 that installed an Omega Seal on the Unit 1 RWCU regenerative heat exchangers 1B and 1C. The DCR made the seals a permanent installed component part of the heat exchangers. Heat exchanger 1A was previously modified with a similar seal. The review also included the applicable safety evaluation. The heat exchangers are not safety related and are located outside the second containment isolation valve.

The heat exchangers had a history of steam leaks that were not contained on a permanent basis. Previous activities to minimize the leaks included liquid sealant, additional banding, installation of cap nuts instead of hex nuts, and welding bolt holes. These actions were not entirely successful. The Omega seal was to prevent the leakage problem.

A review of the maintenance history revealed that the seals were performing very well. No additional leaks were identified since the seal was installed in about 1990.

Unit 2 heat exchangers were not modified with similar seals. They experience leaks but infrequently. Leaks were identified and repaired in May, 1994 and January, 1996. Leaks were routinely repaired with (KOPPLE) liquid sealant. Licensee management stated there were no immediate plans to install similar seals on Unit 2. ALARA considerations for overall dose for the maintenance activity was prohibitive.

The inspectors concluded the evaluation conducted prior to the Omega seal installation was thorough and correct. System leakage as well as availability following the maintenance activity improved.

4.6 Struthers-Dunn Voltage Relay

As the result of the failure of a timing relay, which was manufactured by Struthers-Dunn, the licensee became aware of a manufacturing error whereby an AC coil was installed in a relay intended for DC systems. The licensee stated that they planned to replace any relays having this defect as soon as possible; however, they indicated there may be a period of time the unit would operate before the new relays arrived onsite. In light of this situation, the inspector requested that engineering ensure that the design basis with regard to voltage adequacy was still met given the fact that a relay with possibly a significantly

different resistance than assumed in the calculations was installed. In addition, the inspector raised the issue of whether relay contacts which were in series with the defective relays and had been making and breaking the relay current could have been overdutied. The licensee stated they would pursue this matter.

4.7 Inspection of Open Items

4.7.1 (Closed) LER 50-321/94-09: Main Steam Line High Flow Isolation Setpoint Not Within TS Limits, Rev 1. The licensee issued this LER dated September 22, 1994, when they discovered that a portion of a sentence was omitted from the original LER. The inspectors reviewed the omitted information and determined that no additional licensee or inspector actions were required to close this LER. Based upon this and the previous review, this LER is closed.

5.0 Plant Support Activities (64704) (71750) (83750) (92701) (93702)

Security, health physics and other plant support activities were routinely observed and monitored during the report period. These activities included plant security access controls, locked high radiation area doors, proper radiological posting, personnel frisking upon exiting the RCA, and status of various FPP equipment. The observations and monitoring were performed in conjunction with the conduct of other inspection activities.

5.1 NOUE For Potentially Contaminated Injured Individual Transported Offsite

On April 20, a NOUE was declared after a contract worker fell approximately ten feet off a scaffolding in the Unit 1 drywell. The individual suffered head and possible chest injuries. Part of the workers anti-contamination clothing was removed prior to leaving the site but the individual was not frisked prior to transport to Appling County General Hospital in Baxley Georgia. Later at the hospital, HP personnel determined the individual was slightly contaminated. The individual was decontaminated and transported to Savannah by helicopter for further evaluation. The NOUE was terminated at 10:36 a.m.

The inspectors were notified of the problem. One inspector reported to the site to investigate the problem and observe licensee activities. The inspector reviewed the applicable procedures associated with the problem. The inspector concluded licensee actions following the problem were in accordance with approved procedures.

A second inspector also proceeded to Appling County General Hospital to observe licensee activities for control of the contaminated individual. The inspector observed that an RCA

boundary with a step off pad was established. Radiation signs and postings were in place. The inspector observed that HP management, Safety Engineer, HP technicians as well as a representative from Appling County Emergency Management Representative organization were present.

The inspector concluded activities to stage the hospital site were conducted in accordance with procedures. Overall radiological controls and supervisory oversight were good.

The inspectors discussed the problem with licensee management, outage personnel and individuals assigned to investigate the circumstances surrounding the fall injury. One of the licensee investigators entered the drywell to view and make photographs of the scaffolding and work area. He informed the inspectors that part of the scaffolding guardrail for personnel fall protection was not present. His tour of the drywell did not identify guardrail material that was removed from the scaffolding. Other craftsmen reported to him that, at sometime prior to the hot torque work activity the scaffolding guardrail appeared to be completely intact. It was unclear as to circumstances surrounding the removal of the scaffolding guardrail.

The inspectors concluded that a failure to ensure scaffolding guardrails were present, failure to identify deficient scaffolding, and inattentiveness contributed to the fall injury. The inspectors concluded that no regulatory requirements were violated. However, increased attention to personnel safety matters may reduce the possibility of similar problems.

5.2 External and Internal Exposure Controls

This program area was reviewed to evaluate the adequacy of licensee RP controls for internal and external radiation hazards and to verify individual radiation doses did not exceed the dose limits described in Subpart C of 10 CFR Part 20. Selected elements of the licensee's personnel exposure control program were reviewed during the inspection through direct observations, review of records and discussions with licensee personnel.

During tours of the licensee facilities, the inspector verified radiological postings were appropriate for the radiological hazard, radiation monitoring equipment was operational and used appropriately, high radiation areas were properly controlled, personnel were wearing dosimetry properly and independent radiation surveys agreed with licensee surveys. The inspector observed good use of process and engineering controls to limit exposures to airborne radioactivity. No discrepancies were identified during those tours.

The licensee reported the following maximum doses (Rems) for individuals in calendar years 1995 and 1996 year to date:

Maximum Individual Radiation Doses				
Year	TEDE	Skin	Extremity	Lens-Eye
1995	2.315	2.428	6.239	2.315
1996	1.487	1.530	2.664	1.487
Limits				
Part 20	5.000	50.000	50.000	15.000
1996 data through April 11, 1996.				

The highest internal doses assigned for 1996, at the time of the inspection, was 0.029 rem CEDE. All external and internal exposures were well within the regulatory limits. No concerns with individual radiation exposures were identified.

5.3 Control of Radioactive Materials and Contamination, Surveys and Monitoring

This area was reviewed to determine whether surveys and monitoring activities were performed as required and to evaluate the licensee's control of radioactive and contaminated material.

Housekeeping through the facility was generally adequate. However, the Turbine Building was cluttered and untidy as was the Unit 2 HP satellite office and the hot machine shop. During walk-throughs, the inspector noted scaffolding storage areas were also dirty and untidy. The inspector noted a large amount of sand on the floor in the Unit 1 Turbine Building West Cableway. Licensee personnel reported the sand was deposited on the floor from ground water leakage into the Turbine Building.

The inspector reviewed the control of radioactive contamination and material during tours of the facilities. No uncontrolled containers of radioactive material or contamination were identified during the inspections. However, the inspector identified some plastic bag containers that were worn and torn and in need of replacement or repair. These containers were identified to the RP staff for corrective actions.

The total area included in the licensee's decontamination plan was approximately 175,000 ft^2. The licensee excluded the refueling pools, condenser bays, drywells and numerous equipment

rooms from that plan. The licensee reported no overall progress in the decontamination of contaminated floor space during the period of 1993 through 1996. As reported, the minimum and the maximum area contaminated were 6,000 and 30,000 ft^2, respectively, for each year during the period of 1993 through 1996.

The licensee documented PCEs at a threshold of 10,000 dpm above background. The inspector reviewed recent PCE trends and many of the individual PCRs generated in 1996. In 1993 the licensee documented 147 PCEs (1 RFO) and 372 in 1994 (2 RFOs). In 1995 the licensee raised the threshold for documenting PCEs from 5,000 dpm to 10,000 dpm and documented 177 PCEs (1 RFO) that year. The licensee had documented approximately 60 PCEs for 1996 when the inspection was made. The number of facial contaminations increased slightly with the removal of respirators on many jobs for TEDE ALARA considerations. The licensee reported no goals for minimizing the number of PCEs during the period of 1995 through 1996.

Throughout the inspection the inspector observed approximately 10 personnel clothing decontaminations at RCA exits. Most of these personnel contaminations were below the licensee's threshold for documenting PCEs. These observations indicated the licensee was experiencing problems controlling low levels of radioactive contamination within the facility. It did not appear that conditions causing the events were being identified and corrected since the low level contaminations were not captured in the PCR documents. Even when PCEs were documented, the inspector noted that many of the PCRs completed in 1996 failed to document a cause for the contamination or provide descriptions of actions taken or corrective actions to prevent recurrence.

The inspector reported to licensee management that the licensee's high threshold for documenting PCEs, high occurrence of low level personnel contaminations, lack of PCE goals and minimal corrective action documentation for PCEs indicated a general weakness in the licensee's contamination control program.

The inspector reviewed selected licensee radiation survey results and made independent radiation surveys to verify licensee surveys were appropriate. The inspector's survey results generally agreed with licensee surveys and radiological postings.for those areas. The inspector also observed licensee HPTs performing radiation surveys throughout the site.

Title 10 CFR 20.1003 defines a radiation survey as: An evaluation of the radiological conditions and potential hazards incident to the production, use, transfer, release, disposal, or presence of radioactive material or other sources of radiation. When appropriate, such an evaluation includes a physical survey

of the location of radioactive material and measurements or calculations of levels of radiation, or concentrations or quantities of radioactive material present.

Title 10 CFR 20.1501(a) states, in part, Each licensee shall make or cause to be made, surveys that:

(1) May be necessary to comply with the regulations in this part and are reasonable under the circumstances to evaluate

(i) The extent of radiation levels;

(ii) Concentrations or quantities of radioactive material; and

(iii) The potential radiological hazards that could be present.

Title 10 CFR 20.2103, Records of Surveys states, in part, Each licensee shall maintain records showing the results of surveys and calibrations required by 20.1501.

One activity observed by the inspector, where HPTs were making radiation surveys, concerned the transfer of radioactive filter resins used in the chemical decontamination of plant systems. The temporary filter beds were located on the 130 foot elevation of the Unit 1 Reactor Building. The filter resin was to be sluiced through a temporary hose extending across the south side of the Reactor Building, 130 foot elevation, and emptied into a radioactive waste liner contained in a shielded shipping cask located on a transport trailer. Several liners were used to store the radioactive resin. As each liner was filled, the sluicing was suspended and the shielded liner on the transport trailer was moved into the yard for storage. The liners were lifted out of the shipping cast and stored in radiation shields. Since this activity was not routine, RP personnel were not certain how high the radiation levels on the resin transfer line would be. The licensee had placed some temporary shielding across portions of the transfer hose and had HP personnel stationed at each access point into the area to restrict personnel access to the area. When the sluicing began the licensee took numerous surveys along the hose and established radiation and high radiation areas around portions of the line. When these areas had been established the licensee permitted general access through the area once again. The HPTs continued to survey the temporary transfer hose until all of the resin had been transferred into the liners later that evening. Licensee HPTs established a radiation boundary around the area where the liner would be lifted and placed into a liner shield in the yard. The inspector observed HPTs making radiation surveys on the liners and general areas within and along the radiation control

boundary which was posted as a radiation area. The inspector verified that the dose rate along the boundary was less than 5 mrem/hr.

The following day the inspector requested a review of the licensee's surveys made to establish the radiation and high radiation areas for the resin transfer activities in the Reactor Building and the yard. Licensee personnel reported that surveys made during the resin transfer had not been documented. The inspector stated that failure to document the resin transfer surveys in the Reactor Building and in the yard appeared to be violations of 10 CFR 20.2103 requirements. The inspector also stated, that in addition to meeting the regulatory requirements, there were other practical reasons for documenting the survey results. For example, the records of radiation surveys made during the resin transfer process could prove valuable to the licensee in planning the activity in the future or in performing personnel exposure investigations.

This item was identified as VIO 50-321, 366/96-06-10: "Failure to Maintain Records Showing the Results of Surveys Required by 20.1501. This was the licensee's second violation for failure to document radiation surveys in the last two years. The last violation was documented in NCV 95-01-04, issued February 1, 1995.

The licensee's planning for the resin transfer task was adequate but could have been more thorough and specific. The licensee did a good job of restricting general access into the area until radiation levels in the area had been determined. However, the inspector observed missed opportunities to lower the collective dose with this task. For example:

The HPTs did not appear to be organized during their radiation surveys of the resin sluice line. There were numerous HPTs technicians in the work area during the initial sluicing of resin and several took radiation surveys along the transfer line. In some cases two or more HPTs would be surveying the same area. Limiting the number of HPTs taking surveys and/or use of remote monitoring equipment could have reduced the collective dose the HPTs received while making those surveys.

The operator making system alignments for the resin transfer checked for resin through a sight glass in the transfer line repeatedly. On several occasions the operator sat down within inches of the transfer line. A HPT did eventually stop the operator from sitting next to the line. However, clear expectations on the operator's position and frequency for monitoring the sight glass could have reduced collective dose. Use of remote video equipment could possibly have reduced it further.

The inspector's observations were presented to licensee management.

The inspector observed radiation workers performing assignments throughout the facility and in general found the HP job coverage adequate.

5.4 Maintaining Occupational Exposures ALARA

This program area was reviewed to determine the status and effectiveness of ALARA program initiatives in reducing collective dose for the site. Areas reviewed included annual and outage collective dose goals, ALARA initiatives and source term reductions.

A summary of recent collective dose and goals for the site is shown below.

Collective Personnel Exposures (Person-Rem)						
	Annual Dose			Outage Dose		
	Actual	Goal	Title	Actual	Goal	Days
1993	669	630	U1RFO	414	400	62
1994	869	810	U2RFO U1RFO	314 415	314 335	46 46
1995	490	450	U2RFO	308	275	60
1996	279*	575	U1RFO	193*	275	21*

* The 1996 dose information was measured with electronic dosimeters and was current through 04/09/96.

ALARA personnel reported that reductions in the dose received during operating periods had helped the licensee reduce the collective dose in 1995. However, the extension of the Unit 2 RFO caused the licensee to the exceed the outage dose goal by approximately 33 person-rem and the annual collective dose goal by approximately 40 person-rem.

The licensee continued to expand the use of audio, video and tele-dosimetry equipment for radiological monitoring responsibilities to permit remote monitoring of work activities in low radiation dose locations. The inspector observed considerable use of the equipment during the inspection.

The ALARA supervisor reported that the radiation levels on Unit 1 had been generally higher than those on Unit 2 and that the radiation levels had continued to increase on Unit 1 while the

licensee had observed radiation levels stabilizing or decreasing slightly on Unit 2. The licensee had obtained the services of a contractor to decontaminate four licensee systems in 1996. The contractor used a chemical decontamination process to clean the Unit 1 and 2 Fuel Pool Cooling Systems, Unit 1 Recirculation System and the Unit 1 RWCU System. The licensee reported overall DFs of 4 and 10 for the Unit 1 and Unit 2 Fuel Pool Cooling Systems respectively, a DF of 6 for the RWCU System and a DF of 32 for the Recirculation System piping. The licensee believed the decontamination effort would help the licensee continue a downward trend of the site's three year average collective dose and move the licensee close to the median collective dose for BWRs by the year 2000. The licensee estimated the decontamination would save approximately 300 to 400 person-rem through the year 2000. The licensee had not made any plans to utilize the process on any other plant systems, but was considering the process for RHR system decontamination in 1998. The provided resources for the chemical decontamination was evidence of upper management's support for the ALARA program.

During a review of PCEs the inspector noted that on one day (April 5, 1996) of the on-going RFO, approximately eight personnel were contaminated while working in various areas of the Unit 1 RWCU system. All of these radiation workers had radioactive contamination on their faces. Two of those workers received measurable internal contaminations resulting in assignment of internal dose. The amount of internal exposure was only a small fraction of the permitted radiation dose limit. However, the internal contamination was significant enough to alarm the licensee's whole body frisker which effectively prevented the workers from entering the RCA for two days. The inspector learned that the two radiation workers with the uptakes had been installing a flange on the A RWCU pump. The inspector reviewed the radiological controls for the task with licensee personnel. The radiation workers were not required to wear respirators. Licensee HP staff reported the use of respirators for the task was not believed to be ALARA due to the dose rates in the work area. The inspector noted on one licensee survey of the area that smearable contamination levels at the flange area had been as high as 3 rad/hr gamma and 8 rad/hr beta. The licensee believed the use of respirator for the task would not be ALARA as the use of a respirator could extend the exposure time by approximately 25 percent.

Workers performing the same task on the B RWCU pump did not receive similar internal contaminations. The workers on the A pump used an electric wrench to tighten bolts while the workers on the B pump had only used hand tools. The HP staff reported that they were unaware that the workers were going to use the electric wrench and that it appeared the use of this tool was the primary cause of the internal contamination. There were no HPTs inside the work area providing coverage of the activities. The

inspector determined that the workers in the A RWCU pump room had to clean the flange surface prior to installation and that could have been the cause of the airborne radioactive contamination. The inspector determined that the licensee had not initiated a deficiency card to investigate the event, determine root cause and document corrective actions to prevent recurrence, despite possible benefits of such an exercise.

The licensee had conducted a specific TEDE ALARA review for the task prior to the start of work. Air samples in the work area had not identified airborne radioactive material there. Without specific knowledge that a radioactive airborne area exist the licensee assumed that most work done without a respirator in a high radiation area was ALARA. At the inspector's request, the licensee compared the dose received without a respirator with the dose the two workers might have received with the respirator. The licensee reported:

Worker A received 73 mrem DDE without a respirator and the licensee estimated the dose with a respirator would have been 91 mrem DDE. Worker A's assigned CEDE was 14 mrem so the actual TEDE dose was 87 mrem. This indicated use of a respirator was not ALARA and the licensee saved 4 mrem dose.

Worker B received 33 mrem DDE without a respirator and the licensee estimated the dose with a respirator would have been 41 mrem DDE. Worker B's assigned CEDE was 29 mrem so the actual TEDE dose was 62 mrem. This indicated the use of a respirator was ALARA and the licensee could have eliminated 21 mrem of dose the worker received with a respirator.

Licensee HP management reported the use of respirators in the Unit 1 RWCU Pump A room may have been appropriate considering the planned work and the radiation and contamination levels. The licensee reported the recent trend to reduce the use of respirators to save total dose may have limits and more careful consideration on the use of respirators was warranted in highly contaminated areas.

Based on direct observation, discussion and review of records the inspector concluded the licensee was utilizing some ALARA techniques and making progress in reducing collective doses for the staff. However, attention to details in planning appeared weak for the activities observed by the inspector. In the observed activities, the licensee missed opportunities to reduce dose by a few mrem on several occasions.

Prior to performing the inspections discussed in paragraphs 5.2-5.3 of this report, the inspectors reviewed the applicable portions of the FSAR that related to the areas inspected. There was minimum information concerning the Hatch RP program in the Unit 1 FSAR. However, the Unit 1 FSAR Chapter 13, Conduct of

Operations, did reference the Unit 2 FSAR Chapter 12, Radiation Protection as the document describing the site RP program. For the specific areas reviewed, the inspector verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters. No discrepancies with the actual RP program were identified during the review.

5.5 Control Of Transient Fire Loads

The accumulation and removal of waste oil was part of the licensee's activities during the current Unit 1 refueling outage. The inspectors observed approximately 25 metal drums (55 gallon size) of waste oil and EHC fluid staged at the 130 feet elevation "working floor area" of the Unit 2 turbine building. The drums were located near the end of the east cable way area.

The inspectors reviewed the FHA, procedures, 40AC-ENG-008-OS: Fire Protection Program, Revision 8, and 31GO-OPS-011-OS: FHA Operating Requirements, Revision 0. These procedure delineate the requirements for control of transient fire loads, and control of flammable and combustible liquids. The Fire Protection Program procedure outlined conditions that required transient combustible permits for transient fire loads. The inspectors reviewed the transient combustible permit for the location where the metal drums of waste oil was stored and four additional permits.

The inspectors observed that four of the five permits had expired. The procedure was silent on the requirement for permit extension. The permit for the drums of waste oil expired on December 29, 1995. The permit indicated the area was established as a temporary oil storage area. The permit was otherwise satisfactory for the temporary storage of waste oil. The inspectors observed that the temporary oil storage area was used for a short period of time during unit outages.

The inspectors discussed the expired permits with a fire protection engineer. The inspectors were informed that the permit extension was the responsibility of the permit holder. However, the permit expiration date recorded at the time the permit was issued was a best guess for the length of time needed. Expiration date extensions were generally always approved. The inspectors observed that the computer tracking program for permits included fire loading for all permits until they were closed out and removed from the system.

The inspectors concluded the expired dates on the permits presented no safety significance. However, attention to detail for this activity could be improved. In general, transient fire loads, flammable, and combustible liquids were controlled in a satisfactory manner. The inspectors did not identify any deficiencies with respect to plant practices and the FHA.

6.0 Other NRC Personnel On Site

On April 29 - May 3, 1996, the NRR Senior Project Manager for Hatch, Mr. K. Jabbour visited the site. Mr. Jabbour met with the resident staff and discussed plant status and generic issues. He toured the plant, attended licensee management plant status meetings and reviewed plant documents.

7.0 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. During a portion of the inspection period March 31 - May 11, 1996, the inspectors reviewed the applicable sections of the UFSAR that related to the inspection areas discussed in this report. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors.

Unit 1 FSAR section 3.4 states in part that, the CRD system, with accumulators, provides the following average scram performance at any reactor pressure... a table presented information for 5%, 20%, 50%, and 90% of full control rod stroke. Additionally, stroke in inches for the listed percentages as well as the required time for movement in seconds was presented (paragraph 4.3).

Unit 1 TS table 3.1.4-1, Control Rod Scram Times, indicated rods were to be tested with respect to scram times for four different notch positions of each control rod. The TS did not address average scram times as referenced in the FSAR. There were no direct correlation with respect to control rod positions referenced in the FSAR and TS. There was no procedure requirement to verify the recorded average scram times met the FSAR requirements (paragraph 4.3).

Unit 1 FSAR section 7.2.5, Inspection and Testing of RPS, discussed single rod scram test using the toggle switches on the protection system operations panel. The FSAR stated in part that, "prior to the test, a physics review is conducted to assure that the rod pattern during scram testing does not create a rod of excessive reactivity worth". Engineering personnel stated that reactor power changes were evaluated and taken into consideration prior to single rod scram testing. However, that was not a formal proceduralized process (paragraph 4.3).

Unit 1 FSAR section 4.8 referenced the RHR Steam Condensing Mode of operation. This mode of operation was defeated and part of the equipment was removed during March, 1996, refueling outage (paragraph 3.1.2 and 3.1.3).

Unit 1 FSAR section 4.7 referenced the RCIC steam inlet bypass valve (F119). This valve was removed during the March, 1996, refueling outage.

8.0 Exit

The inspection scope and findings were summarized on May 22, 1996, by Mr. B. L. Holbrook, with those persons indicated by an asterisk in paragraph 1. Interim exits were conducted on April 12, 1996. The inspector described the areas inspected and discussed in detail the inspection results. A listing of inspection findings is provided. Proprietary information is not contained in this report. Dissenting comments by the licensee were noted concerning the proposed Violation of 10 CFR Part 20.2103 requirements for failure to maintain records showing the results of surveys required by 20.1501. Additionally, comments were received with respect to NRCs assessment that the control of low level radioactive contamination appeared to be a program weakness.

Type	Item Number	Status	Description and Reference
NCV	50-321/96-06-01	Closed	Delay in Making 10 CFR 50.72 Notification for ESF Actuation (paragraph 2.6).
VIO	50-321,366/94-17-01	Closed	Failure to Keep Records Documenting Remedial Training Performed and Failure to Document Activities Required by Training Department Procedures (paragraph 2.7).
IFI	50-321,366/96-06-02	Open	VT-3 Examination of Tie Rod Nut Locking Devices (paragraph 3.0.2).
VIO	50-321/96-06-03	Open	Failure to Follow Procedure During Safety Related Valve Maintenance (paragraph 3.0.4).

VIO	50-321/96-06-04	Open	Failure to Meet TS Surveillance Requirements Prior to Withdrawal of a Control Rod While in Cold Shutdown (paragraph 3.2).
VIO	50-321,366/96-06-05	Open	Ineffective Corrective Actions to Strengthen the Technical Specification Surveillance Program (paragraph 3.2).
VIO	50-366/95-21-01	Closed	Inadequate Control of Special Processes (paragraph 3.3.1)
URI	50-321,366/94-25-01	Closed	Review of Previous Ultrasonic Examination Data (paragraph 3.3.2).
URI	50-321,366/96-06-06	Open	Review of Scram Time Testing Methodology and Physics Review Prior to Single Control Rod Scram Time Testing (paragraph 4.3).
NCV	50-321/96-06-07	Closed	Less Than Fully Adequate Test Procedure Results in Loss of Reactor Vessel Inventory (paragraph 4.4).
VIO	50-321,366/96-06-08	Open	Incorrect Set Points for Molded-Case Circuit Breakers (paragraph 4.5.2).
IFI	50-321/96-06-09	Open	Review of Unit 1 DCR Work Deficiencies and Licensee Corrective Actions (paragraph 4.5.4).

LER	50-321/94-09, R1.	Close	Main Steam Line High Flow Isolation Setpoint Not Within TS Limits, Rev 1 (paragraph 4.7.1)
VIO	50-321,366/96-06-10	Open	Requirements for Failure to Maintain Records Showing the Results of Surveys Required by 20.1501 (paragraph 5.3).

9.0 Acronyms

AC - Alternating Current
ALARA- AS Low As Reasonable Achievable
ANII - Authorized Nuclear Inservice Inspector
ASME - American Society of Mechanical Engineers
ATWS - Automatic Trip Without Scram
BPV - Bypass Valve
B&PV - Boiler and Pressure Vessel Code
BU - Bulletin
BWR - Boiling Water Reactor
BWRVIP- Boiling Water Reactor Vessel and Internals Projects
CDE - Committed Dose Equivalent
CEDE - Committed Effective Dose Equivalent
CFR - Code of Federal Regulations
CRD - Control Rod Drive
DC - Direct Current
DCR - Design Change Request
DDE - Deep Dose Equivalent
° - Degrees
DF - Decontamination Factor
DPM - Disintegrations Per Minute
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EHC - Electro Hydraulic Control
EOP - Emergency Operating Procedure
EP - Emergency Preparedness
ERT - Event Review Team
ESF - Engineered Safety Feature
FAS - Fluid Actuator Supply
FHA - Fire Hazards Analysis
FJS - Fluid Jet Supply
FLC - Full Load Current
FPP - Fire Protection Program
FME - Foreign Material Exclusion
FSAR - Final Safety Analysis Report
FT - Foot
FW - Feedwater
GE - General Electric
GL - Generic Letter
GPC - Georgia Power Company

HP - Health Physics
HPT - Health Physics Technician
HPCI - High Pressure Coolant Injection
HR - Hour
" - Inches
I&C - Instrumentation and Controls
ID - Inside Diameter
IFI - Inspector Followup Item
IR - Inspection Report
ISI - Inservice Inspection
IST - Inservice Testing
KV - Kilovolt
KVA - Kilovolt Amperes
KVAR - Kilovolt Amperes Reactive
KW - Kilowatts
LER - Licensee Event Report
LPCI - Low Pressure Coolant Injection
LLRT - Local Leak Rate Test
LSFT - Logic System Functional Test
MCC - Motor Control Center
MDC - Minor Design Change
MOV - Motor Operated Valve
MREM - Milli-rem
MSIV - Main Steam Isolation Valve
Mwe - Megawatts Electric
MWT - Megawatts Thermal
MWO - Maintenance Work Order
NCV - Non-Cited Violation
NDE - Non-Destructive Examination
NOUE - Notice of Unusual Event
NPSH - Net Positive Suction Head
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
OD - Outside Diameter
ODCM - Offsite Dose Calculation Manual
PASS - Post Accident Sampling System
PCE - Personnel Contamination Event
P&ID - Piping and Instrument Drawing
PCIS - Primary Containment Isolation System
PCR - Personnel Contamination Report
PDR - Public Document Room
PSIG - Pounds Per Square Inch Gauge
PSW - Plant Service Water System
QC - Quality Control
RCA - Radiological Controlled Area
RCIC - Reactor Core Isolation Cooling
Rev - Revision
RFO - Re-Fueling Outage
RFPT - Reactor Feedwater Pump Turbine
RG - Regulatory Guide
RHR - Residual Heat Removal

RP - Radiation Protection
RPIS - Rod Position Indication System
RPS - Reactor Protection System
RT - Repair Tag
RTP - Rated Thermal Power
RWCU - Reactor Water Clean-up
RWP - Radiation Work Permit
SAER - Safety Audit and Engineering Review
SER - Safety Evaluation Report
SIL - GE Surveillance Information Report
SNC - Southern Nuclear Operating Company
SOR - Significant Occurrence Report
SP - Special Purpose
SPDS - Safety Parameter Display System
SR - Surveillance Requirement
SRO - Senior Reactor Operator
SRV - Safety Relief Valve
SS - Station Service
TEDE - Total Effective Dose Equivalent
TI - Temporary Instruction
TIL - Turbine Information Letter
TLD - Thermoluminesecent Dosimeter
TS - Technical Specifications
TSI - Thermal Science Incorporated
TSV - Turbine Stop Valve
U1RFO- Unit 1 Re-Fueling Outage
U2RFO- Unit 2 Re-Fueling Outage
UFSAR- Updated Final Safety Analysis Report
URI - Unresolved Item
UT - Ultrasonic Testing
VAC - Alternating Current (Voltage)
VIO - Violation
VT - Visual Testing