U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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| License Nos: | DPR-57 and NPF-5 |
| Report Nos: | 50-321/97-02, 50-366/97-02 |
| Licensee: | Southern Nuclear Operating Company, Inc. (SNC) |
| Facility: | E. I. Hatch Units 1 & 2 |
| Location: | 11030 Hatch Parkway North<br>Baxley, Georgia 31513 |
| Dates: | February 23 - April 5, 1997 |
| Inspectors: | B. Holbrook, Senior Resident Inspector<br>E. Christnot, Resident Inspector<br>J. Canady, Resident Inspector<br>G. Kuzo, Senior Radiation Specialist, (Sections R1.3, R1.4, R5, R7, and R8)<br>W. Kleinsorge, Reactor Inspector, (Section M1.7)<br>N. Merriweather, Reactor Inspector, (Section E1.3) |
| Approved by: | P. Skinner, Chief, Projects Branch 2<br>Division of Reactor Projects |

Enclosure 2

## EXECUTIVE SUMMARY

Plant Hatch, Units 1 and 2
NRC Inspection Report 50-321/97-02, 50-366/97-02

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of an announced inspection by a regional Radiation Specialist and two Reactor Inspectors, one for the maintenance area and one for engineering area.

Operations

- The inspectors concluded that, in general, operator logs were current and accurate. Inspectors observed minor errors of negligible safety significance. However, the errors were considered examples of inattention to detail of administrative tasks (Section O1.2).

- A Non-Cited Violation (NCV) was identified for failure to follow procedures to ensure that Unit 1 Emergency Core Cooling System Room Cooler Control Switches were in the required positions (NCV 50-321/97-02-01) (Section O1.3).

- The inspectors concluded that general refueling activities were well controlled with close management involvement and supervisor oversight. Operations performance during fuel shuffle activities was considered excellent, with no personnel errors. Health Physics (HP) personnel provided radiological control and monitoring support. Site Engineering provided direction and assistance to ensure fuel moves were correct. Contract personnel assigned to the refueling floor were aware of ongoing activities, unit status and provided coordination of work activities (Section O1.4).

- Radiological and Foreign Material Exclusion (FME) controls on the refueling floor were excellent. Operator and Engineering communications, using the phonetic alphabet to identify fuel assembly serial numbers, during refueling floor activities were excellent. Technical Requirements Manual (TRM) and procedural requirements for refueling floor communications and the number of refueling personnel assigned to refueling activities were met (Section O1.5).

- An example of VIO 50-321, 366/97-02-02: Failure to Follow Procedure - Multiple Examples, was identified for the improper restoration of a clearance that resulted in an automatic start of an Emergency Diesel Generator. The inspectors concluded that inattention to detail and inadequate clearance review contributed to the violation (Section O1.6).

- The inspectors did not observe any deficiencies in the system lineup during an Engineered Safety Feature System walkdown of the Main Control Room Environmental Control System. Several items that demonstrated poor housekeeping conditions were promptly corrected. The inspectors did not identify any discrepancies during the Final Safety Analysis Report and Technical Specification reviews (Section O2.1).

- The proposed Final Safety Analysis Report (FSAR) change accurately reflected the Decay Heat Removal (DHR) system use as the primary heat removal system during portions of the refueling outage. Operations management demonstrated conservative decision making with respect to operator training and DHR system monitoring and testing requirements prior to system use. The DHR system met the required TS actions statements for Residual Heat Removal (RHR) System out of service conditions. Operators and Engineering personnel involved with the DHR system demonstrated a thorough understanding of the DHR system functions and operation (Section O3.1).

- The inspectors concluded that, when the licensee learned of the potential problem for Fuel Design-specific Emergency Operating Procedure (EOP) parameters for General Electric Type 13 Fuel, immediate corrective actions were taken to review and implement EOP revisions. The administrative controls implemented to prevent Unit 2 startup until the revisions were completed, were appropriate and conservative (Section O3.2).

- A violation was identified for a late 10 CFR 50.72 Notification For An Engineered Safety Feature Actuation for Containment Isolation, (50-366/97-02-03) (Section O4.1).

- Inspectors identified an Inspector Follow-up Item (IFI) for review of operator performance deficiencies and licensee corrective actions, (IFI 50-321,366/97-02-04). Several recent inattention to detail items were identified (Section O4.2).

- The Code of Federal Regulation requirements for the NRC form 3 postings were met. Postings were adequate for review by licensee employees. Notices of Violations associated with radiological working conditions were appropriately posted (Section O6.1).

- The inspectors reviewed the latest Institute of Nuclear Power Operations (INPO) report and concluded that there were no significant differences between the INPO report and NRC evaluations (Section O8.1).

Maintenance

- Routine maintenance activities were generally completed in a thorough and professional manner. No deficiencies were identified by the inspectors (Section M1.1).

- The inspectors concluded that the procedural requirements for listing applicable procedures in the Maintenance Work Order (MWO) package for specific work activities was not clear. The failure to list the rigging inspection procedure as a required procedure appeared to be a vulnerability to miss procedural requirements (Section M1.2).

- The inspectors concluded that the Direct Current (DC) power systems reviewed were maintained and tested in accordance with approved Preventive Maintenance (PM) procedures and surveillance tests. The replacement of the fire pump and Station Service (SS) batteries were performed in accordance with approved MWOs and with Engineering and supervisory oversight (Sections M1.3 and M1.4).

- The work activities involving the removal and replacement of the Plant Service Water Air Release Valve were performed in a thorough, conscientious manner. Housekeeping was good and FME practices were excellent. Engineering support of maintenance was excellent (Section M1.5).

- An example of VIO 50-321, 366/97-02-02: Failure to Follow Procedure - Multiple Examples, was identified for Maintenance personnel performing work on a valve actuator with the electrical power energized. The inspectors concluded that poor work controls and communications contributed to the problem (Section M1.6).

- Inservice inspection activities observed and/or reviewed were conducted in accordance with procedures, licensee commitments and regulatory requirements (Section M1.7).

- Weaknesses were noted relating to licensee inspection personnel climbing on piping, and a poor inspection technique relating to magnetic particle testing activities (Section M1.7).

- The inspectors concluded that the licensee demonstrated conservative judgement when maintenance was deferred on the 2B Reactor Building Chiller (RBC) due to High Pressure Coolant Injection system (HPCI) maintenance. However, the licensee should evaluate conducting a risk evaluation prior to removing the HPCI and Turbine Chiller System from service under changing conditions that have a high probability of placing the unit in a very high risk condition (Section M4.1).

Engineering

- Pre-staging work activities associated with the Power Range Monitoring Design Change Request did not jeopardize any safety systems or place the unit at risk for transients or scrams. The 10 CFR 50.59 screening and evaluation appeared to be appropriate (Section E1.1).

- The selected Design Modifications observed were performed in accordance with approved procedures. No deficiencies were identified by the inspectors (Section E1.2).

- The Power Range Neutron Monitoring System (PRNMS) modification on Unit 2 was being adequately implemented. Corporate and Site Engineering provided good day-to-day support on implementation of the modification and timely resolution of problems (Section E1.3).

- A violation was identified for failure to specify or reference applicable regulatory requirements, design bases, and other requirements necessary to assure adequate quality in the procurement documents for the Units 1 and 2 NUMAC PRNMS parts. (VIO 50-321, 366/97-02-05) (Section E1.3).

- An example of VIO 50-321, 366/97-02-02: Failure to Follow Procedure - Multiple Examples, was identified for the failure to properly identify that Design Change Request work activities affected fire barriers. The responsible design change implementer failed to identify fire protection requirements (Section E2.1).

- An example of VIO 50-321, 366/97-02-02: Failure to Follow Procedure - Multiple Examples, was identified for craftsman performing work activities, while implementing a Design Change on the 2B Reactor Building Chiller, that were not specified in the work instructions. Poor supervisory oversight contributed to the problem (Section E2.2).

- The inspectors concluded that the engineering inspection of the General Electric Type 13 fuel was appropriate. The inspections were conducted in a controlled manner using appropriate methods and procedures (Section E2.3).

- The inspectors concluded that the small amount of debris removed from the Unit 2 torus did not present an operability concern for Emergency Core Cooling Systems (ECCS) equipment, due to potential suction strainer blockage. Management provided good oversight of contractor work activities. FME controls were maintained in accordance with procedures (E2.4).

- The observed Design Change Request activities were performed in accordance with procedures and approved work process sheets and the required testing was documented. No deficiencies were identified by the inspectors (Section E2.5).

- The training of new fuel inspectors was conducted in a thorough and competent manner. Immediate corrective actions were taken for an NRC identified unmarked FME area on the refueling floor. Housekeeping was good (Section E5.1).

Plant Support

- The inspectors concluded that, in general, radiological controls were satisfactory with designated personnel assigned to monitor and control radiological activities. However, some examples of poor radiological practices were observed (Section R1.1).

- The inspectors concluded that licensee actions to control personnel access to a radiological "Hot Spot" area of the Unit 2 torus were appropriate. The gamma scan and engineering evaluation completed prior to flushing the particles to the reactor vessel were appropriate and reasonable. Overall radiological controls for this activity were considered excellent (R1.2).

- Radiological controls for high and locked high radiation areas were maintained in accordance with TS requirements. Area postings and container labels were appropriate (Section R1.3).

- Poor radiation control practices associated with U2 outage work were identified. (Section R1.3).

- Engineering controls for minimizing internal exposure were effective. Potential uptake of radionuclides were evaluated appropriately. The service air compressor system supplied Grade D respirable air in accordance with 10 CFR 20, Appendix A requirements (Section R1.4).

- General Employee Training (GET) and completed medical certifications for personnel involved in the sampled licensed activities were conducted in accordance with the licensee procedures and met the applicable requirements of 10 CFR Part 19 and 10 CFR Part 20 (Section R5).

- A Safety Assessment Engineering Review (SAER) self-assessment of the Radiological Protection program was performance based and identified significant issues. The line organization was satisfactorily correcting identified audit findings (Section R7.1).

- As Low As Reasonably Achievable (ALARA) program initiatives were implemented in accordance with licensee procedures and were effective (Section R8.1).

- The Technical Support Center was well maintained and in emergency response condition. All communication equipment checks were satisfactory (Section P.2).

- Areas of security inspected met the applicable requirements (Section S2).

- An IFI was identified for review of qualifications and training for fire watch personnel. (IFI 50-321, 366/97-02-06). The inspectors concluded that the majority of individuals attending a GET class, who are subject to be assigned certain fire watch duties, were not aware of the different types of fire watches and in some cases not aware of the expectations and/or qualification requirements for performing fire watch duties. The licensee's subsequent revisions to the training were timely and appropriate (Section F5.1).

# Report Details

## Summary of Plant Status

Unit 1 operated at 100% rated thermal power (RTP) throughout the report period, except for routine testing activities.

Unit 2 began the report period at 100% RTP. A controlled shutdown to begin the 13th refueling outage was initiated on March 14, 1997. The unit reached Cold Shutdown on March 16, and began a scheduled 34 day refueling outage.

## I. Operations

### O1 Conduct of Operations

#### O1.1 General Comments (71707)

Using inspection Procedure 71707, the inspectors conducted frequent reviews of plant operations. In general, the conduct of operations was professional and safety-conscious. Specific events and observation are detailed in the sections below.

#### O1.2 Review of Operator Logs and Documentation

a. Inspection Scope (71707)

The inspectors reviewed procedure 31GO-OPS-006-0S, "Conditions, Required Actions, and Completion Times," Revision 3, 341GO-OPS-007-0S, "Shift Logs and Relief of Personnel," Revision 9, DI-OPS-57-0393N, "Outage Safety Assessment," Revision 6, and conducted a review of operator performance for selected activities associated with the above procedures.

b. Observations and Findings

The inspectors reviewed operator logs to determine which Technical Specification (TS) Required Action Statement (RAS) was implemented during maintenance activities for a breaker on the Unit 1 4160 Volt AC (Alternating Current) electrical switchgear 1G. Inspectors observations of the maintenance activities are discussed in Section M1.2 of this report. On March 5, 1997, documentation indicated that RAS 3.8.7.B was entered for the switchgear breaker. This RAS is for the Direct Current (DC) power distribution system and not the AC system. The correct RAS was 3.8.7.C. The DC system RAS has a 12 hour completion time and the AC system RAS has a time of 8 hours.

On March 6, 1997, RAS 3.8.7.A was entered for a Unit 2 electrical breaker. This RAS was for a Unit 1 AC or DC power distribution system and has a completion time of 7 days. The correct RAS was again, 3.8.7.C.

Additionally, on a few occasions operator log entries did not correctly indicate the results of the Outage Safety Assessment Checklist. The placards posted to reflect the Outage Safety Assessment were accurate and operators were aware of the current status of plant systems. The inspectors discussed these observations with Operations management.

c. Conclusions

The inspectors concluded that, in general, operator logs were current and accurate. Inspectors observed minor errors of negligible safety significance. However, the errors were considered examples of inattention to detail of administrative tasks .

O1.3 Mispositioned Unit 1 Control Room Panel Switches

a. Inspection Scope (71707) (92901)

On March 17, 1997, Operations management informed the inspectors that the control switches for some Unit 1 Emergency Core Cooling System (ECCS) area coolers were discovered to be in an incorrect position. The inspectors reviewed applicable procedures, observed control room switches and discussed the problem with Operations management and Engineering personnel.

b. Observation and Findings

The switches discovered in the incorrect position were for the area coolers for the 1A Core Spray (CS) system and the 1A Residual Heat Removal (RHR) System. On March 17, 1997, when the position of the switches were observed, the operators declared the 1A CS and RHR systems inoperable, entered the correct TS RAS, 3.5.1.H, immediately placed the switches in the correct positions, verified system operability and exited the RAS.

The inspectors observed the switches on the Unit 1 control room panel. Each switch has 4 positions labeled: OFF - STBY - AUTO - RUN. The required position of the switches is AUTO for the automatic start function, when the pumps are started. The switches were discovered in the STBY position. This defeated the automatic start function associated with an automatic pump start.

The inspectors were informed that the switches were manipulated on the day prior to the discovery when the coolers were operated to obtain vibration data for equipment trending. The licensee could not determine conclusively that the switches were mispositioned on that date. However, the licensees investigation revealed that operators ran the system to support maintenance in gathering vibration data, from memory and without the use of a procedure.

The licensee conducted a walk down of the Unit 1 Control Room (CR) panels and found no other switches mispositioned. The inspectors also verified ECCS switches were in the correct position. The licensee initiated an Event Review Team (ERT) to review of the problem and recommend corrective actions. The ERT identified human performance problems as well as some human factor differences among Unit 1, Unit 2 and the plant simulator for switch nomenclature. The ERT made several recommendations to prevent recurrence. Management was evaluating the recommendations for implementation.

Corporate Engineering conducted an evaluation of the mispositioned switches with respect to the design safety function of the ECCS room coolers. With the switches in the standby position, the coolers would have started and operated when the area temperature reached a predetermined setpoint of about 140° F. The area coolers would have performed their intended safety function and the area temperature would not have exceeded 148° F.

c. Conclusions

The inspectors concluded that the CR switches were most likely in the incorrect position for approximately 24 hours and covered at least two operating shift changes. The inspectors documented in Inspection Report (IR) 50-321, 366/95-15 an observation of another mispositioned switch that had little safety consequence.

In this case, operators immediately entered the required TS RAS, and placed the switches in the correct position. Operators then verified the system operated as designed.

This licensee identified and corrected violation constitutes a violation of minor safety significance and is being identified as Non-Cited Violation (NCV) 50-321/97-02-01: Failure to Use Procedure to Ensure That Emergency Core Cooling System Room Cooler Control Switches Are In the Required Positions, consistent with Section IV of the NRC Enforcement Policy.

O1.4 General Refueling Activities

a. Inspection Scope (60710)

The inspectors reviewed applicable procedures for various refueling activities, and observed worker and management involvement in refueling functions to verify procedural requirements were met.

b. Observations and Findings

The inspectors conducted routine tours in the plant and refueling floor and observed general work activities. Health Physics personnel established a permanent work station on the refueling floor and provided radiological control and monitoring support. HP personnel frisked tools and material involved with testing, inspection and moving items within and around the spent fuel pool and reactor vessel cavity. Radiological Control Area (RCA) boundaries were clearly marked and workers complied with the boundary markers.

Operations personnel completed the fuel shuffle with no reactivity control errors. Operations supervision and management were actively involved in the fuel shuffle activities and provided close supervision for refueling floor and refueling bridge activities.

The General Electric (GE) contractors, who functioned as refueling floor coordinators, were well aware of ongoing activities and assisted in maintaining control of equipment, activities, foreign material exclusion (FME), and work functions. They, as well as Operations personnel, monitored fuel pool water level and informed control room personnel.

Site Engineering personnel provided direction and support during the fuel shuffle activities. They constantly monitored fuel moves and provided fuel move verification in accordance with procedural requirements.

c. Conclusions

The inspectors concluded that general refueling activities were well controlled with close management involvement and supervisor oversight. Operations performance for fuel shuffle activities was considered excellent, with no personnel errors. Site Engineering provided direction and assistance to ensure fuel moves were correct. Contract personnel observed were well aware of ongoing activities and unit status and provided coordination of work activities.

## 01.5 Fuel Movement Observation and Refueling Bridge Activities

### a. Inspection Scope (60710)

The inspectors reviewed procedures 34FH-OPS-001-OS, "Fuel Movement Operation," Revision 14, 42FH-ERP-014-OS, "Fuel Movement," Revision 13, Technical Requirements Manual (TRM) 3.9.2, Communications, and observed fuel movement from the Unit 2 refueling bridge and verified that fuel movement was being performed in accordance with the applicable procedures.

### b. Observations and Findings

On April 1, 1997, the inspectors observed fuel movement from the Unit 2 refueling bridge. The inspectors verified a minimum of three personnel were present during fuel movement activities. The fuel moves were being conducted in accordance with the pre-established fuel movement sheets and were verified by a lap-top computer and the refueling grapple camera. The inspectors observed that constant communication between the refueling bridge and the main control room was maintained. The phonetic alphabet was used in identifying the fuel assemblies during communications between the refueling bridge and control room personnel.

Proper radiological and FME controls were maintained on the refueling floor. Housekeeping was observed to be good.

### c. Conclusions

FME controls on the refueling floor were excellent. Operator and Engineering communications, using the phonetic alphabet to identify fuel assembly serial numbers, during refueling floor activities were excellent. TRM and procedural requirements for refueling floor communications and the number of refueling personnel on the refueling bridge were met.

## 01.6 Inadvertent Start of the 1B Diesel Generator from Unit 2

### a. Inspection Scope (71707)

At 5:45 p.m., on April 2, 1997, with Unit 1 at 100% of RTP and Unit 2 in a refueling outage, the 1B Emergency Diesel Generator (EDG) started. The inspectors reviewed procedure 30AC-OPS-001-OS, "Control of Equipment Clearance and Tags," Revision 15, as part of the review of the circumstances surrounding the EDG start. They also discussed the problem with Operations and Maintenance personnel.

b. Observations and Findings

Operators were performing a Temporary Release on clearance 2-97-142 when the EDG started. The inspectors observed that the clearance was initiated to de-energize the 2F 4160V safety related switchgear for cleaning and routine preventive maintenance (PM) activities.

The clearance was performed using procedure 30AC-OPS-001-0S "Control of Equipment Clearances and Tags." The clearance de-energized both the AC power and DC logic control power for the bus. Subsequent to the cleaning and the PMs, the 1B EDG inadvertently started when the DC logic control power was restored.

Licensee personnel stated that this was the third time a Unit 2 safety related 4160 Volt switchgear was restored during the outage. During the two previous restoration activities the corresponding EDG was not in a configuration to automatically start. In this case, the 1B EDG was lined up to start in support of Unit 1 operation. The inspectors found that the DC Logic control power was restored before restoration of the 4160V AC power. When the DC logic power was restored, the DC Logic sensed a loss of power to the 4160V AC bus and the EDG automatically started as designed.

Administrative Control Procedure 30AC-OPS-001-0S, section 8.12, "Temporary Releases," and section 8.13, "Releasing Clearances, Subclearances, and Components," require in part, that the sequence in which a clearance is removed and restored must be specified. Implicit in this instruction is that the sequence be correct. In this case, the restoration sequence was specified but was not in a correct sequence to prevent an unwanted ESF actuation.

c. Conclusions

The inspectors concluded that procedure 30AC-OPS-001-0S was not correctly implemented to prevent an inadvertent EDG started. The clearance restoration sequence was not correct. This is identified as an example of Violation (VIO) 50-321, 366/97-02-02: Failure to Follow Procedure - Multiple Examples. The inspectors concluded that inattention to detail and inadequate clearance review contributed to the violation.

## 02 Operational Status of Facilities and Equipment

### 02.1 Engineered Safety Feature (ESF) System Walkdown (71707)

The inspectors used IP 71707 to walkdown a representative sample of the Main Control Room Environmental Control (MCREC) System components to ensure switches were properly aligned to perform their safety function. The selected components included filter trains, blowers, air handling units, chillers, and associated piping, valves and dampers. The representative sample included the associated instrumentation and controls. The inspectors reviewed the system operation procedure, testing procedures, TS requirements and applicable sections of the FSAR. A discussion was conducted with the engineer certified to perform system Dioctyl Phthalate (DOP) testing.

System lineup was verified to be in accordance with procedure 34SO-Z41-001-1S, "Control Room Ventilation System," Revision 16. The inspectors observed during the system lineup verification that the radiation meter for air discharge to the Unit 1 control room was indicating substantially less than the other radiation meters associated with control room radiation levels. All indications should have approximately the same readings under normal conditions. The inspectors brought this discrepancy to the attention of the control room shift supervisor and a deficiency card (DC) was written.

Minor housekeeping and material condition problems were observed and were reported to the Heating and Ventilation Control (HVAC) performance team supervision for resolution. The inspectors observed on a subsequent tour of the area that the poor housekeeping conditions had been corrected.

The inspectors reviewed deficiency cards (DC) associated with the MCREC System for the past two years and identified no significant deficiencies. In reviewing the Material Safety Data Sheet (MSDS), the inspectors noted that the substance used in performing the DOP testing was a carcinogen. It was further noted that there were no precautions in the procedure addressing the carcinogenic nature of the substance. The inspectors informed the certified engineer for DOP testing of this procedural observation. The engineer informed the inspectors that the carcinogenic nature of the DOP substance was greatly stressed in the training and qualification classes as well as the other hazards addressed on the MSDS. The engineer stated that it was not necessary to place a precaution concerning the carcinogenic nature of the DOP testing substance in the procedure because of the training received for certification and the lack of risk posed by the substance to non-testing personnel.

The inspectors reviewed Unit 2's FSAR, Section 6.4.1, Habitability Systems Functional Design and Section 9.4.1, Main Control Room. These sections of the Unit 2's FSAR cover Unit 1 and 2 since the control room heating and ventilation system is shared by both units. The inspectors also reviewed the requirements of TS 3.7.4, Main Control Room Environmental Control (MCREC) System and TS 3.7.5, Control Room Air Conditioning (AC) System. The inspectors did not observe any significant deficiencies during their review.

## O3 Operations Procedures and Documentation

### O3.1 Review of Decay Heat Removal System (DHR) for Unit 2 Refueling Outage

a. Inspection Scope (71707)

The inspectors reviewed procedure 34SO-G71-001-0S, "Decay Heat Removal System," Revision 5, Edition 1, Unit 1 FSAR section 10.4, Unit 2 FSAR section 9.1.3, Fuel pool Cooling and Cleanup System, a letter dated March 18, 1997, from corporate engineering to Hatch Management, Subject: Use of DHR System During Spring 1997 Outage, and Unit 2 TS 3.9, Refueling Operations. The inspectors walked down the DHR system and discussed system performance with Operations personnel and the system engineer (SE).

b. Observations and Findings

Unit 2 TS 3.9.7, Residual Heat Removal (RHR) - High Water Level, and Limited Condition of Operation (LCO) 3.9.7, specified that one RHR shutdown cooling subsystem shall be operable and in operation. The applicable mode was MODE 5 with irradiated fuel in the reactor pressure vessel. During the current Unit 2 refueling outage, the licensee conducted a fuel shuffle in lieu of a full core offload. This meant that some fuel would remain in the reactor core during the refueling outage. Additionally, the licensee removed both loops of RHR from service to conduct maintenance activities on the common components for both loops of RHR. The licensee used the DHR system to meet the required TS action statements.

The inspectors reviewed Document Change Request 97-05 and the 10 CFR 50.59 evaluation for using the DHR in lieu of RHR Shutdown cooling and to update the FSAR. The inspectors were informed that the FSAR change request would be submitted to NRC in July 1997. The inspectors observed that the 50.59 evaluation did not identify any unreviewed safety question and appeared to appropriately address applicable issues.

The inspectors reviewed procedure 34SO-G71-001-0S. They observed minor discrepancies and brought them to the attention of appropriate management personnel. The inspectors identified that

procedure step 4.3.3 stated in part, to notify the chemistry lab to sample the secondary loop water any time the system was placed in service. However, there were no chemistry procedures or instructions identifying where or how the sampling should be performed. Also, additional sampling to verify system integrity was not specified. Chemistry personnel later informed the inspectors that procedure revisions would include sampling activity requirements and guidance.

The inspectors observed that Operations management demonstrated conservative decision making with respect to DHR procedural requirements and system testing. Procedure section 7.4, Infrequent Operations, described how a fire hose station could be used for a loss of normal make-up water to the cooling towers. Operations personnel made the necessary hose connections and laid out the necessary hose for this infrequent operation. Step 7.2.7.10 specified that system parameter readings would be taken and recorded at the discretion of the Shift Supervisor, but not less than once per shift. The inspectors reviewed the logs and observed that the system parameters were observed and logged hourly.

The inspectors discussed previous and recent DHR system performance with the system engineer. The SE informed the inspectors that the DHR system was recently placed in service to monitor performance and to identify any possible deficiencies. The SE informed the inspectors that minor procedural enhancements were recommended to Operations personnel. The inspectors reviewed procedure 34SO-G71-001-0S and observed that the enhancements were incorporated and the procedure provided clear guidance for both normal and infrequent operations.

Following the test run, some minor system valve control calibrations were completed. The inspectors observed that the DHR system was recently included in the maintenance rule program and receives preventative maintenance prior to the outage in accordance with procedure 52PM -G71-001-0S, "Decay Heat Removal System Preventative Maintenance," Revision 0. The skid mounted Emergency Diesel Generator (EDG), used for the DHR system backup power supply, was started to test its performance while actually providing power to the DHR system. The EDG and DHR system performance was satisfactory.

The inspectors observed the DHR system being placed in service by Operations personnel. The SE was present and provided assistance and guidance. Procedures were used and system parameters were properly monitored.

On March 20, 1997, RHR shutdown cooling was removed from service for maintenance activities. TS RAS 2-97-91 was initiated. Department instruction DI-OPS-57-0393N, "Outage Safety Assessment," accurately reflected that all systems were not available for core cooling.

Operations management directed that all Operations personnel associated with the operation and monitoring of the DHR system review applicable system data and procedures. The personnel were required to review the lesson plan material and to document that the review was completed. The inspectors reviewed Beginning of Shift Training (BOST), 97-07, and System Lesson Plan PE-LP-05801-02, Decay Heat Removal System. The BOST was used as a training vehicle for licensed and non-licensed personnel that would be directly associated with the operation and monitoring of the DHR system. The inspectors verified the study material was the latest revision. The EDG start procedure was posted locally in accordance with procedure and Operations personnel were trained to use the procedure.

c. Conclusions

The inspectors concluded that the proposed FSAR change accurately reflected the DHR system use as the primary heat removal system. The inservice DHR system parameters met the procedure acceptance criteria. Operations management demonstrated conservative decision making with respect to operator training and DHR system monitoring and testing requirements. The DHR system met the required TS actions statements for RHR out of service conditions. Operators and Engineering personnel involved with the DHR system demonstrated a thorough understanding of the DHR system functions and operation.

O3.2 Review of General Electric Service Information Letter (SIL) 529 for Fuel Design-specific Emergency Operating Procedure Parameters (71707) (92700)

On March 10, 1997, the inspectors became aware that another site had discovered that fuel specific action levels and limits used in Emergency Operating Procedures (EOPs) may not be appropriate for certain fuel load conditions. The concern was that EOPs for plants that contained GE Type 13 fuel may need additional review and revision.

Plant Emergency Procedure Guidelines (EPGs) Revision 4 and Severe Accident Guidelines (SAGs) included an Appendix C, which provided formulas to calculate plant-specific action levels and limits used in the EOPs. Data for some of the formula input parameters was fuel-specific or fuel type dependent. The inspectors contacted SE personnel to gain a better understanding of the problem and to

determine if this was a problem for plant Hatch. The inspectors were informed that SE was not aware of the problem but would conduct further inquiries.

Nuclear Safety and Compliance (NSAC) personnel later provided the inspectors a copy of GE Service Information Letter (SIL) 529 Supplement 1, dated March 14, 1997, that discussed the problem. The SIL informed owners of GE BWRs that in addition to the Maximum Subcritical Banked Withdrawal Position noted in SIL 529, dated February 19, 1991, there were other parameters used as input to the Appendix C calculations which are specific to reload fuel design. The SIL specifically identified that use of GE type 13 9x9 fuel would require EOP/SAG re-evaluation. The SIL identified that the Appendix C generic parameters potentially affected by the GE fuel designs included four steam-cooling related parameters and two shutdown boron weight parameters. The SIL recommended that EPG and/or SAG be re-evaluated to ensure that the appropriate input data was used for fuel-related generic parameters in the Appendix C calculations and incorporate any appropriate EOP modification. The inspectors observed that on March 21, 1997, the licensee initiated administrative RAS 2-97-96, to prevent the Unit 2 startup until the appropriate EOPs were revised.

Hatch Unit 1 contains three GE type 13 fuel bundles and Unit 2 contains four. However, during the current Unit 2 refueling outage, 180 additional GE type 13 fuel bundles would be included as part of the new fuel reload. The inspectors were informed that Corporate Engineering was in the process of re-evaluating the EOP Appendix C calculations and would identify any required changes to the EOPs.

Corporate Engineering later provided operations support personnel a list of EOP changes that were required as a result of a re-evaluation of the Appendix C calculations. The inspectors discussed the changes with operations support personnel and reviewed the proposed changes. The inspectors observed that changes were required for the Minimum Alternate Reactor Pressure Vessel (RPV) Pressure, Minimum Core Flooding Interval, Minimum Steam Cooling RPV Water Level and Minimum Zero-Injection RPV Water Level. The inspectors did not review the technical adequacy of the EOP changes.

The inspectors concluded that, when the licensee learned of the potential problem, immediate corrective actions were taken to review and revise the EOPs. The administrative RAS to prevent a Unit 2 startup until the required EOPs were revised was appropriate and conservative.

## O4.0 Operator Knowledge and Performance

### O4.1 Late 10 CFR 52 Notification Following an ESF Actuation

a. Inspection Scope (71707)

The inspectors reviewed procedure 00AC-REG-001-0S, "Federal and State Reporting Requirements," Revision 4, MWO 2-96-0294, Replace Relay Coil, DC 97-1433, Isolation During Maintenance Work and DC 97-1446, Failure to Meet 4 Hour Reporting Requirements. The inspectors discussed their observations with operators, Operations management and Maintenance personnel concerning a Unit 2 ESF actuation on March 25, 1997.

b. Observations and Findings

At 12:06 p.m., on March 25, electrical Maintenance personnel, working MWO 2-96-0294, to replace a bad CR 120 relay coil, accidently grounded a jumper. The relay was being worked with the system logic energized and the jumper was used to prevent system actuation. The grounded jumper resulted in a blown fuse and subsequent partial Group 2 ESF actuation. The blown fuse was replaced, the group isolation was reset and systems were returned to operation.

Operations personnel conducted a panel walkdown to identify systems that may have isolated, recorded components that were suspected of changing position and presented the information to Operations supervision.

The inspectors discussed the problem with operators involved in performing the panel walkdown. The operators informed the inspectors that the number of system components under a protective clearance made the identification of realigned systems more difficult. Engineering personnel assisted the operators in determining system and components that isolated by reviewing the Safety Parameter Display System (SPDS) tape. During this review it was discovered that Unit 1 refueling floor isolation dampers were not verified closed prior to resetting the isolation signal. The inspectors concluded that this was an oversight of Operations personnel performing the panel walkdown. The inspectors reviewed procedure 34AB-C71-001-2S, "Scram," Revision 6, Ed 2, and 34AB-T22-003-1S, "Secondary Containment Control," Revision 5. Either procedure could be used to verify system isolation conditions, and observed that the procedures appeared adequate to verify systems alignment following an ESF.

The inspectors reviewed procedure 00AC-REG-001-0S, "Federal and State Reporting Requirements," Revision 4, section 27, Four-Hour Reports, which identified the Operations Superintendent on Shift (SOS) as one of the individuals responsible for making the report. Section 27.2 of Attachment 3, Non-Periodic Reporting Requirements, described the conditions and contained instructions for the specific reporting requirements. In this case, Operations supervision failed to ensure the ESF actuation for the containment isolation was reported within the required four hour time period. As a result the four hour NRC notification was made at 5:47 p.m. about one hour and 40 minutes beyond the required reporting time. The inspectors reviewed the licensee performance with respect to late NRC notifications during the last two years. The inspectors documented a NCV for a late 10 CFR 50.72 report in Inspection Report (IR) 50-321, 366-96-06 and a VIO in IR 96-10. Both previous instances were different in nature and the recent problem would not have reasonably been prevented by previous corrective actions.

c. Conclusions

This is identified as VIO 50-366/97-02-03: Late 10 CFR 50.72 Notification For An Engineered Safety Feature Actuation for Containment Isolation. The failure of operators to verify proper system isolation prior to resetting the isolation signal was an oversight. The inspectors concluded that the technician placing the jumper demonstrated appropriate work practices and a physical slip caused the short.

## 04.2 Operator Performance During Unit 1 Turbine Valve Testing

a. Inspection Scope (71707)

The inspectors reviewed procedure 34SV-N30-003-1S, "Main turbine Monthly Turbine Test," Revision 2, DC 97-1334, Half Scram During Turbine Testing, and discussed operator performance during Unit 1 turbine testing, with Operations management.

b. Observations and Findings

On March 21, 1997, while performing step 7.3.10 of procedure 34SV-N30-003-1S, for the main turbine stop valve test, a reactor half scram occurred. The procedure step required, in part, to ensure that the turbine was on pressure control by confirming that the load set was 80-100 MWE higher than actual load, up to a maximum value of 905 MWE, as indicated on load set indicator 1N32-R604. The operator was in the process of lowering load set by depressing the load set push button on the turbine control panel, while observing the load set indicator. During the process of lowering the load set, the turbine bypass valve open indications

illuminated as the bypass valves opened and a reactor half scram occurred. The load set indication never changed position. Operators increased load set; the turbine bypass valves closed; the reactor half scram was reset; and reactor power was promptly reduced to less than 100% RTP.

After the reactor half scram was reset, Operations halted the procedure and investigated the problem. Control room indications revealed that, as the load set was reduced, reactor pressure increased to about 1060 psig, (normal pressure is about 1050 psig) and reactor power increased to about 106% - 108% RTP, as indicated on average power range monitor (APRM) recorders 1C51-R603A-D. This resulted in a half scram on the neutron monitoring system. Investigations revealed that reactor power increased to 2573 MWT for a short time during the transient, this was 15 MWT greater than the licensed 2558 MWT power. The inspectors concluded that the momentary spike in reactor power was not a significant increase with respect to total core power or fuel temperature. Maintenance and GE personnel were contacted to trouble shoot and identify the cause of the problem.

The inspectors discussed the instrument problem with Maintenance and GE personnel. The inspectors were informed that the load set indicator was stuck upscale. Maintenance personnel stated that the load set instrument indicator appeared off scale high, above the required procedure setpoint of 905 MWE. The load set instrument was replaced, tested and returned to service. Maintenance personnel also verified that Unit 2 load set was properly calibrated.

The inspectors discussed the problem with Operations management. The discussion included other control room indicators that were available to the operators that provided indication that load set was actually changing, even though the load set indicator did not change positions. Turbine control valve positions are located on the turbine control panel and control valves close as load set is decreased. Operations supervision stated that the operators did not monitor this indication during the testing activities. Licensee management stated the procedure would be reviewed for possible improvements and operators would be reminded to use all available indications for similar activities.

Operations management informed the inspectors that this event was considered significant and an Event Review Team (ERT) was initiated to investigate this and other recent operator performance deficiencies. Other recent operator performance deficiencies are documented in sections O1.2 and O1.3 of this report and in Inspection Report 50-321,366/96-15.

c. Conclusions

The inspectors will review operator performance and the ERTs root cause and recommended corrective actions during future inspections. This issue is identified as Inspector Follow-up Item (IFI) 50-321, 366/97-02-04, "Review of Operator Performance Deficiencies and Licensee Corrective Actions."

## O6 Operations Organization and Administration

O6.1 Review of 10 CFR 19.11, Postings of Notices to Workers (71707)

10 CFR 19.11, Posting of notices to workers, require the licensee to prominently post current copies of NRC Form 3. The postings are required to be in a sufficient number of places to permit individuals engaged in licensed activities to observe them on the way to or from any particular licensed activity location to which the document applies, be conspicuous and be replaced if defaced or altered.

The inspectors reviewed several NRC Form 3 postings and observed that they were the new form dated September 1996. The inspectors concluded that the forms were appropriately posted, were not defaced and were in sufficient number for appropriate review by licensee employees.

The inspectors reviewed the licensee's actions with respect to the Code of Federal Regulation requirements for the NRC Form 3 postings and concluded that the forms were appropriately posted, were not defaced and were in sufficient number for appropriate review by licensee employees. The inspectors also observed that Notice of Violations associated with Radiological Working conditions were appropriately posted.

## O8 Miscellaneous Operations Issues (71707) (92901)

O8.1 Review of Institute of Nuclear Power Operations (INPO) Report

During the period of December 2-13, 1996, INPO conducted an evaluation of Hatch Nuclear Plant activities to make an overall determination of plant safety, to evaluate licensee management systems and controls and to identify areas needing improvement. The results of the evaluation were presented to site management on February 6, 1997. On March 18, the inspectors reviewed the INPO report and concluded that there were no significant differences between the INPO report and the NRC evaluations that required additional follow-up inspection activities.

# II. Maintenance

## M1 Conduct of Maintenance

### M1.1 General Comments

a. Inspection Scope (62707)

The inspectors observed or reviewed all or portions of the following work activities:

- MWO 1-96-4535: Exchange 1B RHRSW Pump Motor with Rebuilt
- MWO 1-96-4446: PM on 1B RHRSW Pump Electrical Breaker
- MWO 2-96-2887: Remove and Replace Valve 2P41-F332D
- MWO 2-96-1657: EDG Preventative Maintenance
- MWO 2-96-2941: EDG Standby Lube Oil Pump PM
- MWO 2-97-0219: Safety Relief Valve Bench Test
- MWO 2-96-1929: Replace 2B Station Service Battery
- MWO 2-96-2358: Cleaning of 1F Switchgear

b. Observations and Findings

The inspectors found that the work was performed with the work packages present and being actively used. Additional comments for maintenance activities are documented in the following sections.

c. Conclusions on Conduct of Maintenance

Maintenance activities observed were generally completed in a thorough and professional manner. The inspectors identified no deficiencies.

### M1.2 Residual Heat Removal Service Water (RHRSW) Pump Motor

a. Inspection Scope (62707)

The inspectors reviewed and observed partial performances of maintenance procedures 52PM-R22-001-0S, "4160 Volt AC Switchgear and Associated Electrical Components Preventive Maintenance," Revision 12, 52IT-MEL-003-0S, "High Potential and Megger Testing of Electrical Equipment and Cables," Revision 7, and 52PM-E11-005-0S, "RHR Service Water Pump and Motor Maintenance," Revision 7. The procedures were used for the exchange of the 1B RHRSW pump motor and supply breaker preventive maintenance (PM). The inspectors also reviewed procedure 52IT-MLH-005-0S, "Rigging Inspection Procedure," Revision 4. The inspectors discussed their observations with licensee management.

b. Observations and Findings

The exchange of the RHRSW pump 1A motor with a refurbished motor was due to a decreasing Polarization Index (PI). The work was performed under Maintenance Work Order (MWO) 1-96-4535. The rigging lifts during the work activities were performed in a safe manner. New lubricating oil was placed into the replacement motor and a PI test was performed with acceptable results.

The PM performed on the pump 4160V AC supply breaker involved racking out and removal of the breaker from the safety related 1G 4160 Volt AC switchgear. The work was performed under MWO 1-96-4446.

The inspectors were informed of a seismic concern involving breakers being racked out of switchgears and either being left in the switchgear cubicle or unattended in the vicinity of the switchgear. Licensee personnel recently constructed a device that fits under the breakers and prevents the breakers from moving on their installed rollers. This device was used during PM activities, while the breaker was unattended in the vicinity of the switchgear. Licensee management informed the inspectors that switchgear breakers would not be left in the cubicles in the racked out condition.

The inspectors reviewed procedure 52AC-MNT-001-0S, "Maintenance Program," Revision 24, Section 8.2.1, Safety Related Work, and Attachment 1, Maintenance Work Order. The section indicated that Block 20, Procedure Number, and Block 23, Work Instructions, of the MWO, Attachment 1, will reference applicable procedures or sections/subsections of procedures as well as drawings, prints, and manuals pertaining to the work.

MWOs 1-96-4446 and 4535 referenced applicable maintenance procedures, manuals, and drawings for such tasks as: terminating the motor leads, meggering, the pump mechanical seal change, inspecting and lubricating the breaker, and general housekeeping requirements.

The inspectors found that MWO 1-96-4535 did not reference procedure 52IT-MLH-005-0S, as an applicable procedure. The procedure provides instructions for inspecting rigging equipment prior to use and includes rigging slings, shackles, eyebolts, turnbuckles, and chains; and the recommended frequency prior to placing rigging equipment in service.

The inspectors discussed this observation with licensee management. Management believed that listing the rigging inspection procedure in the MWO package was unnecessary because individuals who were required to perform rigging inspections were

well aware of the procedure and its requirements. However, management stated that the procedure would be reviewed for applicability.

c. Conclusions

The inspectors concluded that the procedural requirements for listing applicable procedures in the MWO work package for specific work was not clear. The failure to list the rigging inspection procedure as a required procedure appeared to be a vulnerability to miss procedural requirements.

M1.3 Emergency Diesel, Station Service and Fire Pump Batteries

a. Inspection Scope (62707) (61701)

Prior to and during the Unit 2 refueling outage the inspectors reviewed, observed and discussed with licensee personnel the activities involved with various DC electrical power systems. These included the 2A and 2B EDG, the 2A and 2B Station Services (SS) and the 1A and 1B Diesel Engine Driven Fire Pump (DFP) DC systems.

b. Observations and Findings

The inspectors observed portions of the work activities performed on the DC power systems. The DC systems included the batteries and battery chargers. This include required PMs such as battery terminal resistance and specific gravity readings of individual cells.
The inspectors observed portions of the following surveillance performance tests:

- 42SV-R42-003-0S: Battery Inspection
- 42SV-R42-007-0S: Battery Charger Capacity Test
- 42SV-R42-007-0S: Combined Service Performance and Modified Performance Test

The results of the surveillance tests indicated that the batteries exceeded the 100% manufacturer's capacity rating. The requirements are that the batteries be equal to or greater than 80 percent of capacity rating.

The inspectors observed portions of the replacement activities for DFP batteries and the 2B SS batteries. The systems engineer (SE) determined that the replacement of the six fire pump batteries cells, two per pump, was due to battery end of life. The replacement of the 120 cells of the 2B SS battery was due to deterioration of the positive plates in 52 of the cells.

c. Conclusions

The inspectors concluded that the DC power systems were maintained and tested in accordance with approved PM and surveillance test procedures. The replacement of the DFP and SS batteries was performed in accordance with approved MWOs, procedures and with Engineering and supervisory oversight.

M1.4 Emergency Diesel Generator Preventive Maintenance

a. Inspection Scope (62703)

The inspectors observed and reviewed the outage PM performed on the 2A and 2C EDG. Procedures 52PM-R43-001-0S, "Diesel Engine Major Inspection," Revision 4, 52SV-R43-001-0S, "Diesel Alternator and Accessories Inspection," Revision 13 and 52IT-MME-006-0S, "Safety Related Valve Bench Test," Revision 11, were reviewed to ensure activities were performed in accordance with the procedures.

b. Observations and Findings

The inspectors observed portions of the work activities involving PMs performed on the Unit 2 EDGs. The PMs included both the engine and the generator. The observed activities included the change out of the generator bearing lube oil, checking clearances in the engine, replacing the engine coolant, and general cleaning of the engine and generator.

The reviews included the PM procedures and the MWOs implementing the procedures. The MWOs reflected the required procedure activities.

Subsequent to the PMs, a maintenance run was performed on the EDGs. During the maintenance run the generators output was increased to ove· 3000 kW. No deficiencies were observed during the maintenance runs.

c. Conclusions

The inspectors concluded that the PMs were performed in accordance with approved procedures with Engineering and supervisory oversight. No deficiencies were identified by the inspectors.

M1.5 Replacement of Plant Service Water (PSW) Air Release Valve

a. Inspection Scope (62707)

The inspectors monitored the activities associated with the removal and replacement of PSW air release valve 2P41-F332D.

b. Observations and Findings

On March 26, 1997, the inspectors monitored the removal of PSW air release valve 2P41-F332D. The valve had a through-wall pin hole leak in its body. The pin hole leak was discovered in September 1996. The discovery of the pin hole leak and the circumstances surrounding the ASME code relief were discussed in NRC Inspection Report (IR) 50-321, 366/96-13.

The inspectors reviewed the clearance tags for pump control in the main control room, the 4160 2F pump motor breaker in the Emergency Diesel Building, and the local manual PSW pump discharge valve, 2P41-F301D, at the intake structure. No deficiencies were identified in this review. Foreign material exclusion (FME) was implemented to minimize unwanted material from getting into the open piping system.

The inspectors reviewed MWO 2-96-2887. This review revealed that the applicable Quality Control (QC) inspections were signed as being performed. The inspectors also observed engineering support for the work activity.

c. Conclusions

The work activities were performed in a thorough, conscientious manner. Housekeeping was good and FME practices were excellent. Engineering support of maintenance was excellent.

M1.6 Performance of Motor Operated Valve Repair with Breaker to Motor Energized

a. Inspection Scope (62707)

The inspectors reviewed procedure 30AC-OPS-001, "Control of Equipment Clearances and Tags," Revision 15, and clearance 2-97-188. Inspectors discussed with the mechanical maintenance supervisor the removal of the electrical motor driven actuator from PSW isolation valve 1P41-F313D, while the breaker for the associated motor was energized.

b. Observations and Findings

On March 19, 1997, licensee personnel observed a maintenance worker removing the electrical motor driven actuator from valve 1P41-F313D before an approved electrical clearance was in place. The electrical breaker for the valve was in place with power supplied. A mechanical clearance for other work activities being performed on the PSW system was in place and active.

The inspectors were informed by Maintenance personnel that unclear communications between the craftsman and Maintenance supervision led the craftsman to believe conditions were satisfactory to begin work on the valve. The craftsman discussed the system configuration and clearance with a Maintenance supervisor and was informed that no electrical work was to be performed. The mechanic stated he took this reply to mean that it was alright to begin work to remove the actuator since a mechanical clearance was already in place.

The inspectors reviewed clearance 2-97-188 and noted that a mechanical clearance had been completed on March 18, 1997, and the electrical clearance was completed on March 19.

The inspectors reviewed procedure 30AC-OPS-001-OS, Section 4.2.2 and noted that Maintenance management/supervision is responsible for ensuring that isolation boundaries on equipment clearances are adequate for the work to be performed. Section 4.7.1 states, in part, that all personnel are responsible for observing equipment for the presence of DANGER tags and adhering to the requirements of the procedure. A note in section 8.8.3 of the procedure further states that, whether a sub clearance holder signs on a sub clearance or is given a sub clearance by phone, his responsibility is to know that the clearance and its boundaries are adequate for his work.

c. Conclusions

The inspectors concluded that personnel error, poor work control and mis-communication contributed to the removal of the actuator with the breaker to the motor still energized. The removal of the 1P41-F313D valve actuator with the breaker to the motor still energized is a violation of Procedure 30AC-OPS-001-OS; sections 4.2.2, 4.7.1, and 8.8.3. This is identified as an example of Violation 50-321, 366/97-02-02: Failure to Follow Procedure - Multiple Examples.

## M1.7 Inservice Inspection

### a Inspection Scope (73753)

To evaluate the licensee's Inservice Inspection (ISI) program and its implementation, the inspectors reviewed procedures, observed work in progress and reviewed selected records. Observations were compared with applicable procedures, the FSAR and ASME B&PV Code Sections V and XI, 1989 Edition no Addenda (89NA).

Specific areas examined included:

- observation of Liquid Penetrant (PT) examination of Weld 2E21-1CS-10B-15
- Magnetic Particle (MT) examination of Weld 2E21-1CS-10B-20
- manual Ultrasonic (UT) examination of Weld 1E111RHR-248-R9
- data acquisition and analysis activities associated with automated UT examination of piping welds using the SMART system and automated UT examinations of reactor vessel welds using the GERIS 2000 system
- review of video tape of the remote Visual (VT) examination of the reactor vessel internals
- review of the Repair and Replacement Program and MWO Nos 2-96-3010, 3019 and 3234.

The inspectors performed an independent evaluation of indications, to confirm the ISI examiners evaluations.

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

The inspectors reviewed records for welders, QC inspectors, and materials utilized in the MWOs. These records included: Welding Procedure Specifications (WPS) and their supporting Procedure Qualification Records (PQR); Welder Performance Qualification (WPQ) records; records attesting to the maintenance of welder qualification; receiving inspection reports and Certified Material Test Reports for welding filler materials; and records attesting to QC inspectors qualification, certification, and visual acuity. The radiographs for the welds in the MWOs examined, were reviewed for both film quality and code compliance.

### b Observations and Findings

The inspectors noted several ISI personnel climbing on 1-inch uninsulated piping and larger diameter insulated piping. The inspector determined that this practice was not consistent with Plant Hatch Administrative Control Practices, and was an indicator

that training relating to this practice was not effective. The licensee stated, that they subsequently reinforced the practice of not climbing on piping without proper authorization in meetings with ISI personnel.

The inspectors noted that the surface examination area of interest on Weld 2E21-1CS-10B-20, was buffed to bright metal. In addition, the inspectors noted that the examiner of record used gray MT particles. Gray particles on a bright metal background provided only marginal contrast. This practice was not consistent with procedure MT-H-500, "Magnetic Particle Examination," Revision 8, paragraph 7.3.2.3, which states in part, "The color of the particles shall provide adequate contrast with the background of the surface being examined." The inspectors asked the examiner if red or black particles would provide better contrast with a bright metal background. The examiner concurred, and then performed the entire examination using red particles. The licensee stated that they subsequently reinforced the importance of good color contrast between MT particles and the background, with the MT examiners. The inspectors considered the examiner used poor judgement in his initial decision to use gray MT particles on a bright metal surface.

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

The repair and replacement activities examined, were conducted by qualified and certified welders, using correct and certified welding filler materials in accordance with qualified WPSs. Procedure Qualification Records were reviewed and determined to be adequate. Quality Control inspectors and radiographers associated with the repair and replacement activities were qualified and certified.

By letters dated December 2, 1996 and March 7, 1997, the licensee requested relief from the Containment Inspection Rule repair and replacement for a period of one year from September 9, 1996.

c. Conclusion

Most ISI activities observed/reviewed were conducted in accordance with procedures, licensee commitments and regulatory requirements. Weaknesses were noted relating to licensee inspection personnel climbing on piping, and a poor inspection technique relating to magnetic particle test activities.

## M3 Maintenance Procedures and Documentation

### M3.1 Surveillance Observations

a. Inspection Scope (61726)

The inspectors observed all or portions of the following Unit 1 and Unit 2 surveillance activities:

- 34SV-E41-002-1S: HPCI Pump Operability
- 42SV-SUV-031-2S: Reactor Building Isolation Logic Test
- 34SV-SUV-018-1S: ECCS Status Check
- 57IT-CAL-015-0S: Calibrate Unit 2 RPS Time Delay Relays
- 42SV-R42-003-0S: Battery Inspection
- 42SV-R42-007-0S: Battery Charger Capacity Test
- 42SV-R42-007-0S: Combined Service Performance and Modified Performance Test

b. Observations and Findings

The inspectors reviewed procedure 34SV-E41-002-1S and procedure AG-MGR-21-0386N, "Evolution Pre-test Briefing Requirements," Revision 0, and attended the pre-job briefing prior to the performance of the HPCI pump operability test. Representatives from all involved departments attended the meeting. This included Operations, HP, Maintenance, and Engineering. Operations personnel conducted the briefing and discussed the requirements of the procedures and testing activities. Attendees asked questions, provided comments and suggestions to ensure a clear understanding of expectations.

c. Conclusions

For the surveillance observed, all data met the required acceptance criteria and the equipment performed satisfactorily. The performance of the operators and crews conducting the surveillance was generally professional and competent. No deficiencies were identified. The inspectors provided minor comments to Operations management with respect observations of the evolution pre-test briefing.

## M4 Maintenance Staff Knowledge and Performance

### M4.1 Review of Scheduled On-Line Maintenance for Systems/Subsystems Outages

a. Inspection Scope (62703)

The inspectors reviewed procedure 90AC-OAP-002-0S, "Scheduling Maintenance," Revision 0, and observed the activities associated with on-line systems/subsystems maintenance outages. The outages were reviewed and observed to assess the compliance with 10 CFR 50.65, referred to as the Maintenance Rule.

b. Observations and Findings

The inspectors reviewed the work scheduling process and the systems removed from service over an extended period of time. Portions of procedure 90AC-OAP-002-0S were used by various licensee personnel. The inspectors observed an example of this procedure usage when the scheduled PM on the 2B Reactor Building Chiller (RBC) was deferred due to High Pressure Coolant Injection (HPCI) system maintenance. With the HPCI out of service, work on the RBC system would be a very high risk activity, as identified in the procedure. The procedure considered both the RBC system and the Turbine Building Chiller (TBC) system as initiators for the HPCI system and both place the unit in a very high risk condition. The TBC is included in the maintenance rule due to a potential closing of the Main Steam Isolation Valves (MSIV)s during periods of hot weather.

On February 19, 1997, TBC 2A was removed from service for PM and modification purposes. The maintenance outage schedule indicated that, with the outside average temperature less than 68° F over a 48 hour period, the maintenance rule concerns did not apply to the TBC.

During the following week, February 23, through March 1, 1997, the Unit 2 HPCI was removed from service for maintenance purposes, while the TBC was still out of service for maintenance. The combination of the TBC and HPCI being out of service simultaneously is identified as a very high risk condition per the procedure because the HPCI is a major contributor to mitigating the problems associated with a possible closing of the MSIVs.

The inspectors found that the HPCI was removed from service based on the average temperature at the time the system was removed from service. The average temperature increased during the HPCI outage and reached the 68° F limit on the day that the HPCI was returned to service. Had the average temperature been greater than 68° F prior to removing both systems from service, the procedure

requires personnel to perform a risk evaluation. However, the procedure did not address a situation where a high probability of changing conditions existed that could result in a unit being placed in a high risk condition.

The inspectors discussed with licensee personnel if a risk evaluation should be performed prior to removing systems from service when it was known that there was a high probability of changing conditions which could result in a very high risk condition and would require a risk evaluation. The inspectors also discussed what actions would have been taken had the temperature increased to the 68° F limit and ongoing work existed for the HPCI system. The personnel responded that an evaluation was not required initially because the average temperature was less than 68° F. They stated that if the temperature exceeded the limit, the situation would have been treated as an emergent condition, such as a failed component, and a risk evaluation would still not be required. The inspectors were later informed that a risk evaluation had been completed the day HPCI was returned to service, at the request of Operations management.

c. Conclusions

The inspectors concluded that the licensee demonstrated conservative judgement when maintenance was deferred on the 2B Reactor Building Chiller due to HPCI maintenance. However, the licensee should evaluate conducting a risk evaluation prior to removing the HPCI and TBC systems from service during times of uncontrolled changing conditions (outside temperature) that have a high probability of placing the unit in a very high risk condition.

## M8 Miscellaneous Maintenance Issues (92700) (92902)

M8.1 (Closed) LER 321/96-15-00: Failed Control Relay Results in an Automatic Primary Containment Isolation System Actuation

The inspectors reviewed the licensee's corrective actions which included replacing the fuse, replacing the relay coil, and evaluating other relays for replacement for similar situations. During the review the inspectors identified that part of the corrective actions which should have been completed by February 28, 1997, were not completed. The licensee informed the inspectors that the reason for the non-completion of the evaluation report was due to an oversight on the part of Maintenance and Nuclear Safety and Compliance personnel.

The inspectors did not identify any previous examples of non-completion of corrective actions as stated in LER's and considered this to be an isolated incident. The licensee promptly initiated actions to complete the corrective actions.

Based upon the inspectors review and licensee's action, this LER is closed.

## III. Engineering

### E1 Conduct of Engineering

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

E1.1 Review of Power Range Neutron Monitoring System (PRNMS) Pre-Staging Work Activities

a. Inspection Scope (37551)

The inspectors reviewed Design Change Request (DCR) 94-008, Installation of GE Nuclear Measurement Analysis and Control (NUMAC) Power Range Neutron Monitoring System for Unit 2, and procedure 40AC-ENG-003-0S, "Design Control," Revision 8. Additionally, the inspectors observed preliminary work staging that involved cable pulls from the computer room to the cable spreading room of the control building.

b. Observations and Findings

On February 27, 1997, the inspectors observed portions of pre-staging work activities associated with the installation of GE's NUMAC PRNMS. Fiber optic cabling was routed through penetration 2Z43-H084F from the computer room to the cable spreading room on the 147 foot elevation of the control building. This cabling will be connected to the process computer and the control room NUMAC PRNMS panels during implementation of the DCR during the upcoming Unit 2 refueling outage.

The inspectors reviewed the 10 CFR 50.59 associated with the DCR package and identified no discrepancies.

c. Conclusions

Pre-staging work activities associated with the DCR did not jeopardize any safety systems or place the unit at risk for transients or scrams. The 10 CFR 50.59 screening and evaluation appeared to be appropriate.

E1.2 Examination of Reactor Vessel Internals

a. Inspection Scope (73753) (92903)

The inspectors reviewed procedures and documents related to the inspection of core spray spargers, vessel internals, core shroud tie rods and jet pump cleaning. The review included special purpose and other special procedures. Among the procedures reviewed were: 51SP-022797-JR-1-2S, "Jet Pump Cleaning," Revision 0, 52SP-021997-JR-1-2S, "Tie Rod Inspection," Revision 0, and Special Purpose Procedure VT-HC57, "Visual Examination of the Reactor Pressure Vessel Internals," Revision 8.

b. Observations and Findings

The inspectors observed contractor personnel and licensee personnel perform some of the inspections of the core spray spargers, the core shroud tie rods, vessel internals and jet pump cleaning. Approved special purpose procedures were used to conduct the activities. Personnel performing the activities observed required safety, refueling floor, and good radiological practices.

c. Conclusions

The inspectors concluded that all observed activities were performed in accordance with approved procedures. No deficiencies involving work activities were identified by the inspectors.

E1.3 Design Changes and Plant Modifications

a. Inspection Scope (37550)

The inspector examined the implementation of a digital retrofit modification on Unit 2 to verify that the as installed digital modification was in accordance with the NRC Safety Evaluation Report (SER), design drawings and licensee commitments.

b. Observations and Findings

Design Change Package (DCP) 94-008 provided design to upgrade the analog power range monitoring system in Hatch Unit 2 with a GE NUMAC-PRNMS digital retrofit with optional stability trip function. The GE NUMAC-PRNMS design was submitted to NRC in licensing topical report NEDC-32410P. The staff review of this topical report is discussed in a SER dated September 5, 1995. The staff determined that it contained acceptable guidance for replacing the existing power range monitors in a boiling water reactor with a digital NUMAC-PRNMS. In a supplemental SER dated December 26, 1996, the staff approved Supplement 1 to NEDC-32410P,

which provided clarification of issues related to the APRM and APRM technical specifications and included proposed technical specifications for the Oscillation Power Range Monitor (OPRM). Hatch Unit 2 was the lead plant to install this digital retrofit.

By letter dated October 29, 1996, as supplemented February 19, 1997, Georgia Power Company, et. al. (the licensee), proposed license amendments to change the TS for Hatch Units 1 and 2. The proposed changes would reflect design changes that upgrade the analog power monitoring system in the two Hatch plants with a GE NUMAC-PRNM, including OPRM function. License Amendment No. 146 approved changes to Hatch Unit 2 TS to be implemented following installation of the NUMAC-PRNMS.

The inspector reviewed the DCP and 10 CFR 50.59 Safety Evaluation and found both to be technically adequate. Both the DCP and Safety Evaluation had been properly reviewed and approved in accordance with licensee procedures. The major features and components of the NUMAC PRNM system were identified as follows:

<u>Features</u>

- 4 APRM/OPRM Channels
- 2 out of 4 Reactor Protection System (RPS) Logic
- Fiber optic Communication
- Semi- Automatic Gain Adjustment
- Core Oscillation Monitoring
- Self-Test/Testing Intervals

<u>Other Equipment</u>

- APRM Fiber Optic Bypass Switch
- Local Power Range Monitor (LPRM) Connectors Panels
- Process Computer Interface

The modification was being implemented through issuance of MWOs with detail work instructions contained in Work Process Sheets. The work had been divided between two groups, electrical and instrumentation and control. The modification included removing the old Power Range Monitor electronics and internal wiring in Control Room Panel 2H11-P608, installing new internal wiring, lifting and relanding and/or reworking many of the existing external cables, adding conduit for inter-bay wiring, installing new rails, swing arms and racks inside panels to support the new NUMAC equipment, and installing new fiber optic cabling. The modification also required installation of four new Operator Display Assemblies, recorder speed control switch, new APRM/IRM recorders, and a new fiber optic APRM bypass switch.

The inspector observed ongoing and completed work activities inside Panels 2H11-P603 and P608 in the main control room and found the quality of the work to be satisfactory. The modification was being implemented through the use of Work Orders with detail work process sheets. The inspector reviewed a sample of the work process instructions, drawings and reference procedures and found that they provided adequate guidance for the technicians to properly install the modification. The inspector noted that the instructions were maintained in the work area and were being followed. The I&C technicians involved with the modification indicated that they had attended a training class on the GE NUMAC-PRNMS prior to implementation of this modification. The training outline and attendance sheets were later reviewed by the inspector and found to be acceptable. The technicians demonstrated a good working knowledge of the work process instructions, drawings and procedures related to the implementation of this modification. The inspector concluded from these observations that the modification was being implemented in accordance with drawings and procedures.

Engineering support for the modification was provided on a 24 hour basis by a team composed of onsite, corporate, A/E, and vendor personnel. The inspector attended several of the turnover meetings held between the incoming and outgoing implementing engineers and other team members. During these meetings they discussed the status of the ongoing modification work and any problems that required Engineering followup and action plans to resolve the problems. Problems with the mounting of the new Operator Display Assemblies (ODAs) on the main control board and a human factors concern regarding the proposed changes in the bypass indication for APRM A are examples of the issues discussed during the meetings. This provided for good day-to-day support and timely resolution of problems.

Five Field Change Requests (FCRs) had been issued against the modification package. Of these, three involved design problems and two involved site preference issues. One design problem was identified on the simulator when a recirculation pump runback on feedwater pump trip caused an unexpected scram. It was observed on the simulator that the adjustment rate of flow bias trip set points was faster than the runback. The trip set point was observed passing by the flux level reading on its way down resulting in a scram. The recirculation flow transmitters were being modified as part of the scope of this modification with Rosemount Smart kits with variable electronic damping from 0 to 16 seconds. However, the modification package did not require any additional damping beyond the inherent sensor response time of 200 milliseconds which is the same as the original plant design. A FCR was initiated to increase the response time of the recirculation flow transmitters to enhance the plant design by

providing for additional scram margin on the above event. The proposed increase in transmitter response time was reviewed by GE for compliance with the design basis of the NUMAC PRNMs. The inspector concluded from this review that design changes were being adequately evaluated.

The inspector reviewed the Factory Acceptance Test (FAT) for Hatch Unit 2 NUMAC PRNM System dated November 9, 1995. The objective of the test was to verify and demonstrate that the PRNMS had been correctly configured, calibrated, and would function as designed. Discussions with the licensee revealed that both site and Corporate Engineering, Operations, and Training personnel were involved during the Software Verification and Validation (V&V) testing and the FAT test for both Units 1 and 2. The Unit 2 FAT test was witnessed by and certain sections were performed by the licensee. The test was satisfactorily completed based on a review of the test log with no software deficiencies being identified. Three test nonconformance items were noted in the test log. One issue involved an exception taken to step 3.1 of the test procedure because analog output cables for recorder and meter outputs were not available. An alternate method was then specified for the test to measure voltage at analog isolator outputs. The two other nonconformances noted involved hardware problems. The first hardware problem involved the APRM B printer which was not working. The proposed resolution was to repair and retest print screen function prior to shipping. The second hardware problem was that the Piezo electric buzzer for APRM C was not working. The proposed corrective action was to repair and retest the buzzer prior to shipping. The GE Project Manager informed the inspector that documentation of the above repairs and retest results would be contained in the GE traveler package which is a quality assurance record. This was not reviewed by the inspector.

The inspector reviewed the GE NUMAC-PRNM panel separation analysis performed for Hatch 1 and 2, and approved on January 6, 1997. The analysis evaluated the PRNM panel wiring design for adequacy of separation to meet functional redundancy requirements. The inspector found that appropriate standards had been referenced and the assumptions were clearly identified. One of the assumptions was that all safety-related circuits routed external to the PRNM panel and to the field side of the terminals in the panel were adequately separated and are unchanged from the current design. A walkdown of the panels was performed by the architect engineer to verify that separation requirements for external circuits entering the 2H11-P608 Panel were adequate. The walkdown results indicated that some additional corrective actions were needed to maintain adequate physical electrical separation of circuits in the panel.

The licensee indicated that the required actions were incorporated into FCR 94-008-05. The inspector concluded from the above that the licensee was adequately addressing the electrical separation issues internal to the panels to meet the GE design assumptions.

The inspector requested information regarding the applicable requirements and standards that the vendor was required to meet in the design, manufacture and testing of the NUMAC PRNMS components. In response to this request for information the licensee discovered on March 26, 1997, that the requisition and purchase order for the Units 1 and 2 NUMAC PRNMS Parts did not specify or reference the required technical and quality standards for the equipment. The Unit 2 technical and quality standards had been identified by design in Request For Procurement 95-024. However, these requirements had not been incorporated into the purchase requisition change order. Change Requests 18 and 19 to Blanket Purchase Order Number 6012598 added the Unit 1 and 2 NUMAC Parts without specifying or referencing applicable technical requirements in accordance with Section 4 of the Hatch Nuclear Plant Quality Assurance Manual. The failure to specify or reference applicable regulatory requirements, design bases, and other requirements necessary to assure adequate quality in the procurement documents for the Units 1 and 2 NUMAC PRNMS Parts was identified to the licensee as a violation of 10 CFR 50, Appendix B, Criterion IV, Procurement Document Control. This is identified as Violation 50-321,366/97-02-05, Measures Did Not Assure that Applicable Regulatory Requirements and Design Basis Were Specified in Procurement Documents for the NUMAC PRNMS Parts.

The Functional Test Procedure for DCR 94-008 was reviewed and found to be technically adequate. However, this test alone would not prove operability of the system. The combination of the functional test and TS surveillances are necessary to verify system operability. The later test procedures were not reviewed.

c. Conclusions

The NUMAC PRNMS Retrofit modification on Unit 2 was being adequately implemented. In most cases the implementing instructions provided adequate detail to properly implement the modification. The quality of the DCP and field installation work was satisfactory. Corporate and Site Engineering provided good day-to-day support on implementation of the modification and timely resolution of problems. The interfaces between Engineering and other organizations were effective. One violation was identified for failure to specify or reference applicable regulatory requirements, design bases, and other requirements necessary to assure adequate quality in the procurement documents for the Units 1 and 2 NUMAC PRNMS Parts.

## E2 Engineering Support of Facilities and Equipment

### E2.1 Fire Protection Penetrations

a. Inspection Scope (92903)

Several Fire Actions (FA) were listed for both units. The actions were listed as being required due to holes in various walls from removal of Cardox ($CO_2$) hose stations. The inspectors reviewed the FAs, applicable procedures and observed some of the degraded fire barriers.

b. Observations and findings

The licensee recently implemented DCR 94-047, to remove selected $CO_2$ hose stations. The DCR removed the hose reels and the connecting piping from the $CO_2$ storage tank. Subsequent to the removal, the licensee discovered that fire rated assemblies and various penetrations were not adequately restored after the removal of the piping. The bolt holes associated with the piping penetrations were not restored. These included penetrations in the Unit 2 East DC switchgear room, various control building walls, Transformer Room 2C/D, and the Unit 2 West DC switchgear room.

The inspectors reviewed the DCR, Drawing H-11814, and the FAs, and determined that the implementation instructions identified that the bolt holes were to be filled. However, the work package instructions failed to identify that the removal of the equipment and subsequent remaining holes affected fire barriers. Maintenance personnel performing the work activity, completed the removal of the equipment but deferred filling some of the bolt holes. Maintenance personnel stated that they were not aware of the fire barrier concerns associated with the bolt holes. As a result the required actions for degraded fire barriers were not implemented at that time. A total of four Maintenance Work Orders (MWOs), 1-96-3030, 3031, 3075, and 2-96-2871, were used to implement the design change. The requirements for fire barrier work activities were also not identified on the MWO documentation.

The inspector reviewed procedure 17MS-MMS-002-0S, "DCR Process," Revision 1, and observed that section 7.4.1 required in part, that prior to issuing MWOs, the responsible implementer was to ensure Special Design Considerations have been identified on MWOs and Welding Procedure Specifications (WPS). In this case, the design consideration, that the equipment removal affected fire barriers, was not identified on the MWOs or WPS.

The inspectors reviewed procedure 50AC-MNT-001-0S, "Maintenance Program," Revision 24, and observed that section 4.9 required in part that, Plant Maintenance and Modification (PMM) personnel were responsible to ensure the Fire Protection Evaluation is completed prior to scheduling work on equipment serving or impacting Fire Protection. In this case, the Fire Protection Evaluation was not performed and the MWOs did not identify any impact to fire protection equipment (Fire Barriers).

c. Conclusions

The inspectors concluded that PMMS personnel failed to follow procedure to identify and document that DCR 94-047 work activities adversely affected fire protection barriers. As result the required FAs for degraded fire barriers were not implemented in a timely manner. Maintenance personnel failed to complete all work instructions identified on the MWOs and WPSs. This item was identified as an example of Violation 50-321, 366/97-02-02: Failure to Follow Procedure - Multiple Examples.

E2.2 Performance Deficiency During Modification Implementation

a. Inspection Scope (92903)

The inspectors reviewed DCR 94-050, Install Vent Piping on the Reactor Building Chiller System, and MWO 2-96-2347, Implement DCR 94-050, and reviewed work performance for the activities. The licensee documented that on at least two occasions equipment may have been adversely affected by activities involving personnel performing modifications.

b. Observations and Findings

On March 10, 1997, a system trouble alarm was received on the Unit 2 Hydrogen Water Chemistry Injection (HWCI) system. The operators observed a large mismatch between the actual flow and the demand flow from the HWCI controller setpoint. A bent air line to the controller was also observed. The operators commented that onsite modifications personnel were working in the area and may have damaged the air line. The system was shutdown, repairs were made, and the system was returned to operation.

The inspectors found from the reviews, discussions, and observations that the degraded operation of the HWCI system may not have been affected significantly by the bent air line but no additional system problems were observed. There is no conclusive evidence that activities by personal performing modifications contributed to the shutdown of the HWCI system.

On March 11, 1997, the 2B RBC tripped. Onsite licensee personnel started the 2A RBC within 15-20 minutes of the trip. The Unit 2 Reactor Building was without chill water for about 20 minutes. No other system problems were identified. The inspectors were informed that onsite modification implementation personnel, installing vent piping on the RBC in accordance with DCR 94-050 and MWO 2-96-2347, had loosened a flange on the cooler for the operating RBC. This resulted in air leakage into a part of the RBC that normally operates under a vacuum and the chiller tripped on over pressure.

The inspectors reviewed licensee documentation, discussed the problems with Maintenance, Operations, PMMS personnel and observed the RBC systems. The inspectors were informed that part of the DCR had been previously implemented and the additional work was to complete the DCR work activity. The discussions indicated that the personnel implementing the DCR were verbally informed that they were working on vent piping only. In an attempt to align piping that they were installing with already installed piping, Maintenance personnel unbolted the coupling next to the RBC cooler. The loosening of the flange on the operating 2B RBC resulted in a chiller trip and rendered the system inoperable. Unbolting the flange was not part of the work instructions.

The inspectors were informed that Engineering management reviewed the problem and concluded that the job supervisor should have provided more detailed instructions to ensure the work was performed as expected. Licensee management initiated employee discipline for the job supervisor.

c. Conclusions

The inspectors concluded that the personnel performing the chiller modification did not receive adequate verbal or written instructions from the work supervisor to ensure the work was performed as expected. The job supervisor failed to inform the workers of the job scope and limits. The craftsman performed work activities that were not specified in the written work instructions. The inspectors did not view this as an engineering design change implementation problem but rather a human interface work control problem. This is identified as an example of Violation 50-321, 366/97-02-02: Failure to Follow Procedure - Multiple Examples.

## E2.3 Review of GE Type 13 Fuel Inspection (37551)

During the Unit 2 fall 1995, refueling outage, four General Electric (GE) type 13 Lead Use Assembly (LA) fuel bundles were included as part of the new fuel reload. Three bundles were fabricated with debris resistant lower tie plates and the other

bundle had a standard lower tie plate. During the current refueling outage, a GE Fuel Inspection Team conducted an inspection of three bundles and conducted a baseline lower tie plate flow test on three bundles. Data from the test will be compared with future measurements on the same bundle to track flow characteristic changes. The licensee was to gain information to determine if the new design of lower tie plate would be included in future fuel reloads. An additional 180 GE type 13 LA bundles will be included as part of the current refueling core load. However, the debris resistant lower tie plates will not be included. Bundle peripheral inspections were conducted on three bundles and six pre-selected individual fuel rods from one of the three bundles.

Licensee inspection data indicated that all lower tie plate holes were open with no evidence of blockage or debris. The debris filter resistant lower tie plates appeared to have small amounts of crud present but nothing was observed to preclude reinsertion and continued operation. The bundle peripheral inspection indicated that crud was heavy from about 10 inches to about 130 inches and prevented observation of the cladding. The bundles had no debris and appeared in excellent condition. The six pre-selected fuel rods were examined visually and appeared to be in excellent condition. A slight shadowing was observed in the spacer contact region but there were no atypical observations.

The inspectors concluded that engineering inspection of the GE Type 13 fuel was appropriate. The inspections were conducted in a controlled manner using appropriate methods and procedures. methods. Other inspector observations associated with GE Type 13 fuel are documented in section O3.2 of this report.

E2.4 <u>Review of Unit 2 Torus Inspection and Desludging Activities (37551)</u>

During the current Unit 2 refueling outage the licensee contracted to have the torus inspected, cleaned and spot painted. The inspectors observed part of the work activities, observed Foreign Material Exclusion (FME) control measures and reviewed the results of the cleaning activities and debris.

FME control for the torus area was identified as an area that needed improvement during the last Unit 1 refueling outage. The inspectors reviewed procedure 10AC-MGR-021-0S, "Foreign Material Exclusion," Revision 8, and observed that the material taken into the torus was properly controlled and that FME procedure requirements were met.

The inspectors reviewed the results of the torus inspection and observed that all 16 bays of the torus were inspected. The report indicated that sludge depths observed were from about 1/8 inches to as much as 6 inches in one small area of bay 9. The inspectors estimated the average depth to be from about .55 inches to about 1.2 inches. The sludge was removed and the sludge dry weight was calculated to be about 118 pounds.

Small debris was found in all bays except bays 11 and 15. The debris included items such as plastic tie wraps, LLRT test line fitting, small pieces of duct tape, scaffold tie wire, washers, nails, wood splinters and miscellaneous metal items. Bays 2, 4 and 14 contained the most material. Much of the debris was metallic, however, some items had the potential to block a small portion of the ECCS suction strainers. Examples included items such as duct tape, small plastic cylinders, white cloth material and two handfuls of insulation. The inspectors discussed with licensee management whether an evaluation of the as found condition was made. On April 5, 1997, the inspectors were informed that an evaluation was being performed by Corporate Engineering and the report had not been finalized.

The inspectors concluded that the small amount of debris did not present a past operability concern for ECCS equipment, due to potential suction strainer blockage. Management provided good oversight of contractor work activities. FME controls were maintained in accordance with plant procedures.

E2.5 Modification Implementation

a. Inspection Scope (37700) (37828)

The inspectors reviewed and observed modification implementation activities. The inspectors reviewed DCR packages, which contained the assessments required by 10 CFR 50.59, unreviewed safety question criteria, required testing, and job task activities.

b. Observations and Findings

Among the DCRs reviewed and activities observed were the following:

- 92-042 Replace 22 Analog Indicators With Digital Type
- 93-048 Modify the Condensate System Demineralizers
- 94-041 Replace the Main Turbine Blades and Thrust Wear Detector
- 95-054 Upgrade the Reactor Feed Pump (RFP) Digital Controls
- 96-018 Modify the Power Supplies for the RFP Controls
- 97-011 Modify the 4160V Safety-related Circuit Breakers

Design Change Request-018 was installed to address a single failure concern involving the loss of both RFPs. This previously identified problem resulted in a manual scram of Unit 1 and is documented in Inspection Report (IR) 50-321, 366/96-07. DCP 97-011 was installed to allow a breaker to be racked out, electrically disconnected from the safety related switchgear bus, and remain inside the switchgear cubicle without impacting the seismic qualification of the switchgear.

c. Conclusions

The inspectors concluded that the observed DCR activities were performed in accordance with procedures and approved WPSs and the required testing was documented. No deficiencies were identified by the inspectors.

E2.6 Local Leak Rate Testing (LLRT)

a. Inspection Scope (61715) (62707)

The inspectors reviewed procedure 42SV-TET-001-2S, "Primary Containment Periodic Type B and Type C Leakage Tests," Revision 18, and observed Local Leak Rate Test (LLRT) activities and reviewed some of the leak test results. A total of 90 penetration, Type B, tests and 147 valve, Type C, tests were scheduled during the refueling outage.

b. Observations and Findings

At the end of the report period 76 Type B and 125 Type C tests were completed. No failures were identified for the Type B tests. A total of 13 Type C failures were identified. The majority of the failures were due to seating surface wear. Of the 13 Type C failures, eight were repaired or scheduled for repair, three valves were replaced with like-for-like, and two valves were scheduled for replacement by modifications. One valve in the HPCI system and two valves in the Reactor Core Isolation (RCIC) system were replaced with like-for-like.

Two valves in the Drywell Sump Drainage Radwaste (DSDR) System, 2G11-F003 and F004, failed the leakage test and an LER was initiated. A review by the licensee indicated that these valves had a poor performance record for the past three or four years and had resulted in issuance of previous LERs. The Plant General Manager directed that all four valves be changed to a more reliable configuration. DCR 97-018 was initiated to affect the change. At the end of the report period the DCR was being implemented.

c. Conclusions

The inspectors conclude that the LLRTs were performed in accordance with approved procedures and with Engineering and supervisory oversight. The inspectors considered the replacement of the four DSDR valves and associated piping under DCR 97-018, demonstrated conservative decision making.

## E5 Engineering Staff Training and Qualification

E5.1 Review of Pre-Refueling Activities

a. Inspection Scope (60705)

The inspectors reviewed procedure 45QC-PQL-001-0S, "Qualification of Inspection Personnel," Revision 4, ED1. On February 21, 1997, the inspectors observed the licensee's training of new fuel inspectors and new fuel inspection activities on the refueling floor. Inspectors conducted a general tour of the refueling floor.

b. Observations and Findings

The training of new fuel inspectors was conducted by certified and experienced new fuel inspectors from the Reactor Engineering section and a GE representative. This training was performed in an on-the-job setting wherein new fuel was actually inspected. No training discrepancies were identified.

The inspectors observed that one of the floor plugs over the new fuel storage vault was removed to allow storage of newly inspected fuel assemblies into the racks below. A railing-type boundary was placed around the opening left by the removed plug for personnel safety. However, the inspectors did not observe a FME boundary. This issue was raised with refueling floor personnel. The area was determined to be an FME area in accordance with procedure 10AC-MGR-021-0S, "Foreign Material Exclusion," Revision 0. Refueling floor personnel immediately barricaded the area with the appropriate material and labelled it as a FME area. New fuel had not been placed in the storage vault at the time of the observation.

Other FME areas on the refueling floor were prominently marked with FME signs and boundary material. Tool control areas were prominently marked and identified with boundary material. Housekeeping was good.

On February 25, 1997, the inspectors observed the retrieval of a telephone that had dropped into the spent fuel pool from the refueling bridge. Discussions with personnel on the refueling

bridge indicated that screws holding the telephone in place had become loose. A person on the bridge brushed against the phone knocking it loose. HP personnel were present on the refueling bridge, monitoring the retrieval process. No discrepancies were observed in the retrieval process.

In a followup visit to the refueling floor, the inspectors were informed that a "wholeness" inspection of the telephone was performed and all parts were present and accounted for.

c. Conclusions

The training of new fuel inspectors was conducted in a thorough and competent manner. Immediate corrective actions were taken for FME problem areas observed on the refueling floor. Housekeeping was good.

**E8 Miscellaneous Engineering Issues** (92700) (92903)

E8.1 (Closed) LER 50-321/96-12: Ground on 600-Volt Bus Causes Loss of RPS Power Supply and Unplanned ESF System Actuations

This LER was issued on October 30, 1996, when a ground on the 600-Volt bus caused ESF actuations. The licensee was previously investigating similar problems and was developing a corrective action plan. The plan included using a different type of breaker trip device which was less susceptible to electromagnetic interference. New trip devices are presently installed and the licensee is evaluating their performance. Based upon the inspectors review and licensee actions, this LER is closed.

## IV Plant Support

**R1 Radiological Protection and Chemistry Controls**

R1.1 Observation of Routine Radiological Controls (71750)

General Health Physics (HP) activities were observed during the report period. This included locked high radiation area doors, proper radiological posting, and personnel frisking upon exiting radiologically controlled area (RCA). The inspectors made frequent tours of the RCA and discussed radiological controls with HP technicians and HP management.

The inspectors observed pre-staging activities for the Unit 2 refueling outage. Activities included moving equipment, establishing RCA boundaries with roping and stepoff pads, posting additional personnel for egress of the RCA and control points for the main turbine and drywell work activities.

The inspectors conducted frequent tours of the main turbine deck area to observe work activities and HP controls. Two HP technicians were stationed near the turbine work area to establish, monitor and maintain proper HP controls. The inspectors observed that some RCA boundaries, although clearly defined, had equipment or material such as protective clothing, ladders, and electrical cords laying across the boundary tape. Several instances observed throughout the plant were brought to the attention of HP personnel who immediately corrected the problem.

The inspectors concluded that, in general, HP controls were satisfactory with designated HP personnel to monitor and control HP related issues. However, some examples of poor HP practices were observed. Other Radiological control observations are documented in section R1.3 and R1.4 of this report.

R1.2 Radiological Hot Spot Identified in Unit 2 Torus

a. Inspection Scope 71750

On March 29, 1997, the inspectors were informed that a radiological hot spot was identified in Bay 2 of the Unit 2 torus. The inspectors reviewed procedure 60AC-HPX-004-0S, "Radiation and Contamination Control," Revision 14, and observed licensee actions with respect to the hot spot area.

b. Observations and Findings

The inspectors observed from review of the radiological survey maps that the hot spot was located in a 20 inch common suction piping to the RHR system. Surveys of the area indicated about 45 Rem/hr on contact and about 8-9 Rem/hr at 12 inches. The inspectors observed from the review of procedure 60AC-HPX-004-0S, "Radiation Control," section 8.1, that, any area with a radiation level of greater than 1 Rem/hr at 30 centimeters from the source be posted as a High Radiation Area and locked. Since the torus area could not be physically locked, HP technicians were posted to control personnel access to the area near the hot spot.

Licensee management evaluated the problem and developed several possible corrective action plans. Part of the evaluation was to determine what particulate material was identified in the hot spot and, based upon the results, determine what actions were most appropriate. Engineering, HP, Operations and GE personnel evaluated the possibility of the hot particles being metallic debris. The evaluation concluded that there was no credible scenario that resulted in metallic debris being deposited in the Residual Heat Removal (RHR) line. There was no known work activity that would have generated metallic debris.

The most likely source of the material causing the hot spot was flaking of corrosion deposits from internal vessel surfaces caused by impact of in-vessel inspection equipment and maintenance tooling being positioned. Similar products and flaking material were observed during the required in-vessel inspections performed this refueling outage.

GE personnel completed a gamma scan of the hot spot area and determined the hot particles consisted of cobalt 60 and zinc 65, which were spread over an approximately 2-3 foot long area and confirmed the hot spot was not a single object. The evaluation further indicated that there was no reason not to flush the hot particles back to the reactor vessel through the normal RHR shutdown cooling line. This activity was successfully completed by April 5, 1997. Following the flush, the hot spot area radiation levels returned to about 50 millirem/HR. This was considerably less than the 250 millirem/HR requirement to post the area as a hot spot.

c. Conclusions

The inspectors concluded that licensee actions to station HP technicians to control personnel access to the hot spot area were appropriate. The gamma scan and engineering evaluation completed prior to flushing the particles to the reactor vessel were appropriate and reasonable. Overall HP actions were considered excellent.

R1.3 Radiological Controls

a. Inspection Scope (83750)

Radiological controls associated with ongoing Unit 1 (U1) operations and with Unit 2 (U2) outage activities were reviewed and evaluated by the inspectors. The reviewed program areas included area postings and radioactive waste (radwaste) container labels, controls for high and locked-high radiation areas, and procedural and radiation work permit (RWP) guidance. Established controls were compared against FSAR details and documented requirements in applicable sections of TSs and 10 CFR Part 20.

The inspectors made frequent tours of the RCA. In addition, specific RWP, procedural guidance and selected survey results were reviewed and discussed with responsible HP staff and supervisors. External and internal exposure controls associated with specific outage tasks performed in accordance with selected RWPs were evaluated in detail. The inspectors directly observed worker and HP technician performance and discussed results of radiation and contamination surveys conducted for selected equipment and facility locations.

b. Observations and Findings

High and locked-high radiation area controls were verified to be implemented in accordance with TS requirements. Postings for radiologically controlled areas were proper and in accordance with TS or 10 CFR 20 Subpart J requirements. Containers holding radwaste, contaminated materials and equipment were labeled in accordance with 10 CFR 20.1904 requirements.

Airborne radionuclide concentrations were minimized during grinding and cleaning of potentially contamination material through the use of appropriate engineering controls, e.g., high efficiency particulate airborne (HEPA) ventilation systems and containment structures. Survey results verified that respiratory protection was not required for the tasks observed.

However, the following poor radiological control practices associated with U2 outage activities within the Turbine Building (TB) and Reactor Building were identified by the inspectors.

- Potentially contaminated equipment, e.g., wrenches, welder mask and hoses, were positioned across established RCA contamination zone boundaries.

- Workers reached over established contamination zone boundaries

- Workers' personal clothing was stored in a cable tray in the Turbine Building (TB) 112 foot (') elevation.

- A contractor used the wrong RWP to conduct outage work within the TB 112' elevation on March 25, 1997.

The inspectors evaluated contract workers' use of RWPs in detail. The inspectors noted that TS 5.4 requires that written procedures be established, implemented, and maintained covering activities delineated in Appendix A of Regulatory Guide (RG) 1.33, Rev. 2, dated February 1978. Regulatory Guide 1.33, Appendix A "Typical Procedures for Pressurized Water Reactor and Boiling Water Reactors", Paragraph 7.e identifies radiation protection procedures for a Radiation Work Permit System. For the contractor identified as using the wrong RWP, the inspectors noted that the work activities involved Condensate Demineralizer valve maintenance in the TB 112' elevation. However, the identified individual was only one of five workers improperly signed in on a non-outage RWP to conduct the required task activities. From discussions with the worker and responsible health physics staff, the inspectors determined that the individual signed-in on RWP 097-0002, Rev. 1, effective January 1, 1997, rather than RWP 297-1500, Rev. 1, effective March 10, 1997. Review of each RWP's

specifications, indicated similarities in dosimetry including digital alarming dosimeter (DAD) settings, protective clothing and training requirements. As of March 28, 1997, the issue was identified as an isolated event. However, during an April 4, 1997 telephone call, Mr. M. Link, a Plant Hatch HP Supervisor informed Mr. G. Kuzo, a Senior Radiation Specialist, NRC RII, that further licensee evaluations identified additional examples of workers using the improper RWP to conduct work within the RCA early in the U2 outage. The inspectors noted that final results of the licensee's evaluation would be reviewed during subsequent inspections.

c. Conclusions

Radiological controls for high and locked high radiation areas were maintained in accordance with TS requirements. Internal exposure for U2 outage tasks was controlled effectively. Radiological area postings and container labels were appropriate. Poor radiation control practices associated with U2 outage work were identified. In addition, followup of licensee identification of several examples of personnel logging into the RCA using the wrong RWP was identified as unresolved item (URI) 50-321, 366/97-02-07: Review Licensee Followup, Results and Significance of Improper RWP Sign-in for Workers Involved in U2 Outage Activities.

R1.4 Internal Exposure

a. Inspection Scope (83750)

The inspectors discussed program guidance for monitoring and evaluating possible internal exposures, and reviewed in detail licensee evaluations for three of five potential uptakes associated with U2 outage activities.

In addition, guidance for testing and results to ensure quality of supplied breathing air for respiratory protective equipment were reviewed and discussed.

b. Observations and Findings

As of March 25, 1997, five instances of potential radionuclide uptake associated with U2 outage activities were identified by the licensee. Evaluations for three of the five potential uptakes were complete. The inspectors verified that the evaluations were completed in accordance with procedure 60AC-HPX-003-0S, "Bioassay Program," Rev. 5, effective October 8, 1996. The maximum uptake was 0.7 percent of the annual limit of intake (ALI) for a worker involved in a March 18, 1997 contamination event. As required by procedure, the inspectors verified that the internal exposure

above 0.2 percent ALI was added to the individual's official exposure records.

The inspectors verified that the compressor systems used to supply breathing air were tested to certify Grade D air for potential use during outage activities. Breathing system air samples were collected quarterly in accordance with 62RP-RAD-003-OS, "Use and Care of Respirators," Rev. 7, effective March 27, 1996. Review of the quarterly sample results since August 8, 1996, verified that the supplied breathing air quality exceeded the established limits for Grade D air specified in the Compressed Gas Commodity Specification G7.1, 1973.

c. Conclusions

Overall, licensee controls for minimizing internal exposure were effective. Potential uptake of radionuclides were evaluated appropriately. Licensee tests verified that the service air compressor system supplied Grade D respirable air in accordance with 10 CFR 20, Appendix A requirements.

## R5 Staff Training and Qualifications in Radiation Protection and Chemistry

a. Inspection Scope (83750)

The inspectors reviewed and evaluated General Employee Training (GET) provided to meet the requirements of 10 CFR Part 19, and the specific training and medical certification requirements specified by 10 CFR Part 20 for persons who used or were designated to use respiratory protection equipment.

Current training and medical certification records for selected personnel within the following groups were reviewed and discussed with cognizant licensee representatives.

- Licensee and contractor personnel who had been issued respirators under various RWPs during March 1997.
- Southern Company employees from non-nuclear facilities temporarily working at the Hatch Plant during the refueling outage.

b. Observations and Findings

The inspectors verified that GET, respiratory protection training, and respiratory medical certifications were conducted in accordance with the requirements of 10 CFR 19.12 and 10 CFR 20.1703. From review of training records and selected "Respirator/Device Issuance Reports" dated during March 1997, the

inspectors verified that persons who used respiratory protection equipment were trained and medically certified in accordance with the applicable procedures

c. Conclusions

GET and completed medical certifications for personnel involved in the sampled licensed activities were conducted in accordance with the licensee procedures and met the applicable requirements of 10 CFR Part 19 and 10 CFR Part 20.

## R7 Quality Assurance in Radiation Protection and Chemistry Activities

### R7.1 Audits

a. Inspection Scope (83750)

The inspectors reviewed and discussed audits of HP and Radiation Protection (RP) program areas associated with the ongoing U2 outage. The inspectors also reviewed the Safety Audit and Engineering Review (SAER) report of the RP program conducted between September 19 and October 23, 1996, the Quality Check program and the November 1996 Self Assessment. The scope, thoroughness and status of corrective actions of the audits were assessed.

b. Observations and Findings

From review of Audit Plan and Checklist details the inspectors verified that an audit of the HP and RP program was scheduled from March 7, through April 18, 1997. Specific audit topics included, occupational radiation exposure reports, high radiation area controls, surveys, RWPs, radiation exposure limits, personnel dosimetry, bioassay program, radiation and contamination control, respiratory protection program, ALARA program, TIP room access and Drywell entry, instrumentation, advanced radworker guidelines and procedural adherence.

The SAER audit reviewed seventeen specific areas in the RP program. The audit consisted of interviews, record review and direct observations. The audit identified four findings and thirteen areas that were satisfactory. The audit was performance based and the content was an adequate sample of the program attributes. The findings were characterized appropriately in the report, were being tracked to closure, and the line organization was appropriately performing corrective actions for the findings. One of the findings addressed the adequacy of the labeling of radioactive material. During tours of the radiological controlled areas, the inspectors did not identify any radioactive material that was labeled improperly.

The Quality Check program was discussed with RP management. Based on those discussions, the inspector learned that this was an informal program used by the RP Supervisors to followup of areas or issues they suspected of being a problem, that there was no set frequency for conducting these checks, and that no formal documentation existed to show that identified issues were actually corrected.

In November 1996, the licensee performed a self assessment audit of the RP program using knowledgeable representatives from other utilities. RP management believed the assessment would be a help in enhancing the site RP program. The inspectors judged the assessment as thorough. The inspectors learned that the findings from the assessment had not been entered into a tracking system until RP management was prompted by an outside organization. Corrective actions for the findings had not been completed at the time of this inspection.

c. Conclusions

A formal self assessment of the RP program conducted by SAER was performance based and identified significant issues. The line organization was satisfactorily correcting SAER audit findings.

## R8 Miscellaneous RP&C Issues

R8.1 ALARA Program Initiatives.

a. Inspection Scope (83750)

Implementation and effectiveness of As Low as Reasonably Achievable (ALARA) initiatives for three separate U2 outage tasks were reviewed and discussed. Program initiatives, current and expected dose (person-rem) and hour expenditures were reviewed for the following tasks.

- RWP 297-1020, Open, repair shield doors, insulation removal/replacement temporary shielding, scaffolding, tent building/removal & support work including subpile room.
- RWP 297-1022, ISI & Support Work
- RWP 297-1036, Install/Modify Control Rod Drive (CRD) Platform and Support Work.

b. Observations and Findings

The inspectors verified that ALARA initiatives were implemented, as applicable, in accordance with guidance specified in 17MS-MMS-002-OS, Design Change Request Processing, Rev. 1, effective October 17, 1996, and 60AC-HPX-009-OS, ALARA Program, Rev. 12, effective December 23, 1996.

Approximately 250 person-rem was budgeted for the current outage with an established goal of 221.602 person-rem. As of March 26, 1997, a cumulative total of approximately 80 person-rem was expended relative to 109 person-rem expected. Excluding RWP 297-1036, man-hours, man-rem and average dose rate budgeted were within original estimates. For RWP 297-1039, Undervessel Platform Installation, numerous reviews and design modifications significantly reduced dose expenditure estimates from 60 person-rem to 15 person-rem. The design changes involved changing from welded to bolted installation and increased prefabrication. As of March 24, 1997 with the task nearly complete, actual dose expenditure was approximately 3.04 person-rem. The differences between the actual and final estimates resulted from lower than expected dose rates.

c. Conclusions

ALARA program initiatives were implemented in accordance with licensee procedures and were effective.

R8.2 Inspector Follow-up of Previous Open Items (83750) (84750)

(Closed) Violation (VIO) 50-321, 366/96-06-10: Failure to Maintain Records Showing the Results of Surveys Required by 10 CFR 20.1501.

The inspectors reviewed the licensee's July 10, 1996 response to the subject violation. Corrective steps taken by the licensee and verified by the inspectors included issuance on July 11, 1996, of Health Physics Information Letter No. 96-09 on "Documenting HP Surveys". Instructions conveyed in this letter established changes in radiation survey practices to require suitable documentation. Appropriate revisions to RP procedure 62RP-RAD-008-OS, "Radiation and Contamination Surveys", Revision 9, were made in February 1997 to add sections on conducting and documenting surveys and a new "Survey Log Sheet". This violation is closed.

## P2 Status of Emergency Preparedness (EP) facilities, Equipment and Resources (71750).

The inspectors conducted several tours of the Technical Support Center (TSC) to verify the facilities were ready to support an event if required. Communications and other emergency response equipment were in place and operable. The inspectors conducted several phone checks to site and NRC locations to ensure all lines were operable. All communication equipment checks were satisfactory. The inspectors concluded that the facilities were well maintained and readily available to support an emergency.

## S2 Status of Security Facilities and Equipment (71750)

The inspectors toured the protected area and observed that the perimeter fence was intact and not compromised by erosion nor disrepair. The fence fabric was secured and barbed wire was angled as required by the licensee's Physical Security Plan (PSP). Isolation zones were maintained on both sides of the barrier and were free of objects which could shield or conceal an individual. The inspectors observed personnel and packages entering the protected area were searched either by special purpose detectors or by a physical patdown for firearms, explosives and contraband. Badge issuance was observed, as was the processing and escorting of visitors. Vehicles were searched, escorted and secured as described in applicable procedures.

The inspectors concluded that the areas of security inspected met the applicable requirements.

## F5 Fire Protection Staff Training and Qualification

### F5.1 Fire Watch Training

a. Inspection Scope (92904)

The inspectors reviewed the licensees requirements for fire watch qualification. The inspectors attended General Employee Traning (GET), reviewed GET material, and observed the training conducted to meet some fire watch qualifications.

b. Observations and Findings

The inspectors attended GET on February 24, 1997. The GET instructor covered subjects such as Radiological Protection, Security, Breathing Protection, Emergency Preparedness, Fire Protection and some regulatory requirements for the topics.

During the training sessions several questions concerning the types of fire watches, fire watch training, and fire watch qualification were raised. A statement was made that fire watches must receive special training in order to be qualified. The general audience appeared to be confused as to what type of special training was needed. Two different types of fire watches were being discussed. One type of fire watch was the Hot Work Fire Watch and the other was the Compensatory Fire Watch. The inspectors were subsequently informed that the fire watch for hot work required special training and the compensatory fire watch only required GET.

After further review and discussion with licensee personnel the inspectors were informed that there are three types of fire watches. These included:

- The Hot Work Fire Watch: This fire watch is a continuous fire watch at or near the area of hot work activities. Special training is required to qualify for this fire watch.

- The Compensatory Continuous Fire Watch: This fire watch is discussed in the Plant Hatch Fire Hazard Analysis (FHA) and is established when fire rated assemblies and/or fire barriers are inoperable. GET meets the requirement to qualify for this watch.

- The Compensatory Fire Watch Patrol: This fire watch is also discussed in the FHA and is established when fire rated assemblies and/or fire barriers are inoperable and the continuous fire watch is not required in accordance with the FHA. GET meets the requirement to qualify for this watch.

These three types of fire watches were not discussed in the GET. Nor were the fire watch requirements nor management expectations for the conduct of fire watches. The inspectors discussed these observation with licensee management and training personnel. The inspectors were aware that Operations recently developed expectations for fire watch activities. However, people outside Operations may perform fire watch duties. The inspectors questioned how expectations were communicated to people outside Operations. The inspectors were later informed that GET material was reviewed and will be revised to ensure fire watch issues are clearly communicated to all employees.

c. Conclusions

The inspectors concluded that the majority of individuals attending the GET class and who are subject to be assigned certain fire watch duties, were not aware of the different types of fire watches. In some cases they were not aware of the expectations and/or qualification requirements for performing fire watches duties. Revising the training was timely and appropriate.

The inspectors will perform a review of fire watch training requirements, fire watch training documentation, and observe and discuss fire watch duties and responsibilities with involved personnel. This is identified as an Inspector Followup Item (IFI) 50-321, 366/97-02-06: Review of Qualifications and Training for Fire Watch Personnel.

## V. Management Meetings

### X.1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on April 17, 1997. The license acknowledged the findings presented. Interim exits were conducted on March 28 and April 4, 1997.

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

### X.2 Review of UFSAR Commitments

A recent discovery of a licensee operating its 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. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The current wording of Unit 1 FSAR section 10.4, and Unit 2 FSAR section 9.1.3, Fuel pool Cooling and Cleanup System, were different from the present licensee practice, however, a proposed FSAR change request and scheduled date for NRC submittal had been developed. This issue is discussed in section 03.1 of this report.

### X.3 Other NRC Personnel On Site

On February 26 and 27, 1997, Mr. P. H. Skinner, Chief Reactor Projects Branch 2, visited the site. He met with the resident inspector staff and discuss plant performance and NRC regulatory

issues. He toured the plant facilities and observed equipment in operation and general plant condition. He also met with licensee management and discussed plant performance and generic regulatory issues.

## PARTIAL LIST OF PERSONS CONTACTED

Licensee

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

## INSPECTION PROCEDURES USED

IP 37550: Engineering
IP 37551: Onsite Engineering
IP 37700: Design Changes And Modifiactions
IP 37828: Installation And Testing Of Modifications
IP 60705: Preparations For Refueling
IP 60710: Refueling Activities
IP 61701: Complex Surveillances
IP 61726: Surveillance Observations
IP 62703: Maintenance Observations
IP 62707: Maintenance Observations
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 73753: Inservice Inspection
IP 83750: Occupational Radiation Exposure
IP 84750: Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP 92700: Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901: Followup - Operations
IP 92902: Followup - Maintenance/Surveillance
IP 92903: Followup - Followup Engineering
IP 92904: Followup - Plant Support

# ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 50-321, 366/97-02-02 | VIO | Failure to Follow Procedure - Multiple Examples (Sections O1.6, M1.6, E2.1, and E2.2). |
| 50-366/97-02-03 | VIO | Late 10 CFR 50.72 Notification for an Engineered Safety Feature Actuation Containment Isolation (Section O4.1). |
| 50-321, 366/97-02-04 | IFI | Review of Operator Performance Deficiencies and Licensee Corrective Actions (Section O4.2). |
| 50-321, 366/97-02-05 | VIO | Measures Did Not Assure that Applicable Regulatory Requirements and Design Basis Were Specified in Procurement Documents for the NUMAC PRNMS Parts (Section E1.3). |
| 50-321, 366/97-02-06 | IFI | Review of Qualifications and Training for Fire Watch Personnel (Section F5.1). |
| 50-321, 366/97-02-07 | URI | Review licensee followup and results of staff RWP adherence (Section R1.3). |

Closed

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|---|---|---|
| 50-321/97-02-01 | NCV | Failure to Follow Procedure to Ensure That Emergency Core Cooling System Room Cooler Control Switches Are In the Required Positions (Section O1.3) |
| 50-321/96-15 | LER | Failed Control Relay Results in an Automatic Primary Containment Isolation System Actuation (Section M8.1) |

| | | |
|---|---|---|
| 50-321/96-12 | LER | Ground on 600-Volt Bus Causes Loss of RPS Power Supply and Unplanned ESF System Actuations (Section E8.1) |
| 50-321, 366/96-06-10 | VIO | Failure to Maintain Records Showing the Results of Surveys Required by 10 CFR 20.1501 (Section R8.2). |