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

Report Nos.: 50-321/94-02 and 50-366/94-02

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

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

Facility Name: Hatch Nuclear Plant

Inspection Conducted: January 02, 1994 - February 05, 1994

Inspectors:	D.A. Seymour for Leonard D. Wert, Jr., Sr. Resident Inspector	3.1.94 Date Signed
	D.A. Se for Edward F. Christnot, Resident Inspector	3.1.94 Date Signed
	D.A. Se for Bob L. Holbrook, Resident Inspector	3.1.94 Date Signed
Approved by:	Pierce H. Skinner Pierce H. Skinner, Chief, Project Section 3B Division of Reactor Projects	3/3/94 Date Signed

SUMMARY

Scope: This routine resident inspection involved inspection on-site in the areas of operations, surveillance testing, maintenance activities, Engineered Safety Feature System walkdown, iodine monitoring program implementation, local public document room visit, and review of open items.

Results: One unresolved item and one non-cited violation were identified:

The unresolved item (URI) addressed inconsistencies involving some applications of radiation monitoring system calibration factors. Questioning by the inspectors resulted in the licensee determining that procedures for offsite radiological release dose projections may not have used the appropriate calibration factors. Additional information and review is necessary to assess the safety significance of this issue (URI 50-321,366/94-02-01: Inadequate Controls Regarding Radiation Monitoring Systems Calibration Factors, paragraph 3c).

The non-cited violation (NCV) addressed deficiencies in the iodine monitoring program. Silver zeolite cartridges which would be used to obtain post accident iodine samples had exceeded the recommended shelf life. Although the problem was identified by

9403150172 940303
PDR ADOCK 05000321
Q PDR

the NRC inspectors, the safety significance was not large and corrective actions were promptly completed (NCV 50-321,366/94-02-02: Iodine Monitoring Program Deficiencies, paragraph 6).

During review of compensatory actions for an inoperable "normal" main stack radiation monitoring system, the inspectors identified weaknesses regarding communications and coordination between the different working groups involved (paragraph 2b). Review of an incident involving underground cables damaged during maintenance activities indicated that controls during the excavation process were insufficient (paragraph 4b). While no specific regulatory requirements were violated in either instance, the inspectors concluded that a stronger interface between the involved work groups would have resulted in better performance.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*D. Bennett, Chemistry Superintendent
S. Bethay, Hatch Licensing Manager, Southern Nuclear
J. Betsill, Unit 2 Operations Superintendent
S. Brunsen, Engineer, Nuclear Safety and Compliance
C. Coggin, Training and Emergency Preparedness Manager
S. Curtis, Operations Support Superintendent
D. Davis, Plant Administration Manager
B. Duvall, Plant Engineering Supervisor
*W. Flowers, SAER Representative
*P. Fornel, Maintenance Manager
*D. Foster, Plant Operator
O. Fraser, Safety Audit and Engineering Review Supervisor
*G. Goode, Engineering Support Manager
*L. Gooden, Shift Supervisor
*M. Googe, Outages and Planning Manager
*S. Grantham, Acting Training and Emergency Preparedness Supervisor
J. Hammonds, Regulatory Compliance Supervisor
W. Kirkley, Health Physics and Chemistry Manager
*L. McDaniel, Acting Manager, Plant Administration
*T. Metzler, Acting Manager Nuclear Safety and Compliance
*C. Moore, Assistant General Manager - Operations
*J. Payne, Senior Engineer
D. Read, Assistant General Manager - Plant Support
R. Reddick, Emergency Preparedness Coordinator
*K. Robuck, Manager, Modifications and Maintenance Support
H. Sumner, General Manager - Nuclear Plant
J. Thompson, Nuclear Security Manager
S. Tipps, Nuclear Safety and Compliance Manager
*P. Wells, Operations Manager

Other licensee employees contacted included technicians, operators, mechanics, security force members and staff personnel.

NRC Inspectors

*L. Wert, Senior Resident Inspector
*E. Christnot, Resident Inspector
*B. Holbrook, Resident Inspector
D. Seymour, Project Engineer

NRC management/officials on site during inspection period:

K. Barr, Chief, Emergency Preparedness Section, Division of Radiation Safety and Safeguards, Region II

A. Herdt, Chief, Reactor Projects Branch 3, Division of Reactor Projects, RII
J. Jaudan, Deputy Director, Division of Reactor Safety, RII
E. Merschoff, Director, Division of Reactor Projects, Region II
L. Plisco, Acting Director, Project Directorate II-3, NRR
L. Reyes, Deputy Administrator, Region II

* Attended exit interview

Acronyms and abbreviations used throughout this report are listed in the last paragraph.

2. Plant Operations (71707) (93702)

a. Operations Status and Observations

Unit 1 began the period operating at 60% RTP in order to repair a steam leak on a balance of plant valve. By January 2, power was returned to 100% RTP. Unit 1 operated at that power level for the remainder of the report period with the exception of power reductions for routine testing.

Unit 2 began the report period operating at 85% RTP. Several control rods remain fully inserted to suppress neutron flux in the area of the suspected fuel leak. On January 13, power was decreased to about 55% RTP in order to perform testing to investigate indications of increasing offgas radiation levels. On January 20, power was returned to 75%. On January 26, power was reduced to 70% RTP and the unit operated at that level for the remainder of the report period.

Activities within the control room were monitored routinely. Inspections were conducted on day and on night shifts, during weekdays and on weekends. Observations included control room manning, access control, operator professionalism and attentiveness, and adherence to procedures. Instrument readings, recorder traces, annunciator alarms, operability of nuclear instrumentation and reactor protection system channels, availability of power sources, and operability of the SPDS were monitored.

Control Room observations also included ECCS system lineups, containment integrity, reactor mode switch position, scram discharge volume valve positions, and rod movement controls. During a tour of the control room on January 3, the inspector noted that an operability test of a CS pump was being performed. Earlier in the day, the inspector had noted that functional testing of an ATTS instrumentation cabinet was in progress. The inspector determined that the control board operators had suspended the ATTS testing during the CS pump operation. The testing did not render the CS pump inoperable. The inspector concluded that this was an appropriate cautionary action.

The inspectors reviewed procedure 30AC-OPS-001-0S: Control of Equipment Clearances and Tags, and conducted an independent walkdown of a Unit 2 RHR loop B clearance. The inspectors verified that system switches, breakers valve positions, and tags (in the CR and locally), were aligned in accordance with the clearance sheet. Also, the inspectors verified that the independent verification, review and approval signatures, and other documentation to complete the clearance forms were completed as required.

The inspectors identified two minor discrepancies associated with the equipment clearance sheet documentation and one minor procedure discrepancy. The discrepancies did not affect personnel or equipment safety and were only a matter of documentation. These discrepancies were discussed with the appropriate licensee personnel. The inspectors concluded that the equipment clearance was conducted correctly and also provided the personnel and equipment protection required for the work activities.

The inspectors reviewed procedure 34SV-SUV-019-2S: Surveillance Checks. This procedure is conducted primarily by control room operators and contains numerous instrumentation TS surveillance requirements such as channel checks, levels, pressures, temperature records and other checks. The procedure is completed daily and some readings are required to be taken each shift. The inspectors performed the procedure by conducting a control room walkthrough and observing all of the listed instruments. The control room instrument readings and setpoints were verified to be within the values as indicated in the procedure. Many of the procedure steps were also verified to be consistent with the TS requirements. Instrument readings were verified to be within the TS allowable value. No deficiencies were identified. The inspectors noted that the procedure referenced some TS sections that were no longer applicable. The requirements for several instruments had been removed from the TS and inserted into the ODCM. The inspectors verified that the requirements in the ODCM were being met by the procedure.

The inspector observed and reviewed the operators activities involved with a failed relay in the CAD system train B. The failure affected the Unit 1 drywell vent isolation valve 1T48-F334B. Clearance 1-94-080 was issued and implemented to establish the boundary of the failure. The licensee identified relay 1T48-K5B as failing due to age. The damaged relay and two additional relays, 1T48-K2B and K65 were replaced. Post maintenance testing was performed by the operators cycling the valves. All observed activities and reviews indicated the process was conducted by the operators in accordance with procedures. The clearance was adequate and the system was properly returned to service.

On February 2, the coil in relay 2A71-K57 failed. This resulted in fuse 2A71B-F22 being blown and the actuation of the outboard

("B" channel) logic for a Group II isolation. The relay was subsequently deenergized, the fuse replaced and the logic was reset. The logic actuation caused several small bore containment isolation valves to close. The appropriate TS LCOs were entered and the NRC operation center was informed of the event as required by 10 CFR 50.72. The operators verified that the required Group II valves actuated. Because of the recent relay failures, the licensee reviewed the failures closely for potential common mode issues. A number of the recently failed relays were continuously energized GE Type CR-120 relays which had been installed in excess of ten years. At the close of the inspection period, the licensee and GE were still investigating the failures. Information indicates that similar failures have occurred at other facilities and may have been attributed to aging. The inspectors will continue to monitor the licensee's corrective actions.

On January 6, 1994, information from the licensee indicated that some deficiencies had been identified concerning the PSW and RHRSW strainers. The licensee also indicated that the deficiencies did not impact operability and involved cracked grouting, undersized bolting, and missing nuts. The inspectors walked down the intake pump room and the valve pit area and discussed the issues with a knowledgeable engineer. The inspectors noted that cracked grouting was present on support pads for the Unit 1 PSW strainers and Unit 2 RHRSW strainers. It was also noted that the bolting for the Unit 2 RHRSW strainers and PSW strainer 2P41-D001B were tagged, indicating the undersized bolting and missing nuts. A followup walkdown was performed by the inspectors accompanied by a licensee representative. The inspectors reviewed an assessment of the degradations which had been performed by SCS. The inspectors concluded that the existing information supported operability of the systems. Information about this issue was forwarded to the NRC service water team, which was onsite, for further review.

Plant tours were taken throughout the reporting period on a routine basis. The areas toured included the following:

Reactor Building	Diesel Generator Building
Fire Pump Building	Intake Structure
Station Yard Zone	Turbine Building
Unit 1 Torus	Main Stack (Lower Elevation)

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed. On January 15, a backshift tour was conducted which included observation of the licensee's cold weather preparations (IR 50-321,366/93-27 contains a review of the licensee's cold weather programs and procedures). The inspector observed that four heat trace indicating lights associated with the intake structure were not lit. Three of the lights were located in the service water strainer pit area and one was located on a traveling water screen line. The ambient temperature had just reached 32 °F and the heat trace circuits are expected to be energized at temperatures equal to or less than 40 °F. The inspector communicated the observations to several maintenance personnel who were assigned the task of ensuring the cold weather equipment was operating properly. Subsequently, maintenance personnel identified and repaired three heat trace circuits in the intake structure which were not operating properly. The inspector noted that a section of fire main piping, which was uncovered for repairs, had been covered in plastic, and a temporary heater was being used to ensure the piping did not freeze. The inspector also noted that CR personnel and supervisors were sensitive to potential problems associated with the cold weather. During a backshift tour on January 19, (ambient temperature was about 16 °F), the inspector noted that the heat trace circuits in the Unit 2 CST enclosure appeared to not be functioning correctly. The inspector informed the SOS who initiated corrective actions.

The unusually cold weather resulted in two minor problems. About 8:00 am on January 19, the CST level indicators in the CR, for both units, failed upscale. These indicators are not used for any safety function. At approximately 9:30 am on January 19, valves 1P41-F310A and F310D began to closed. These valves isolate PSW to the TB, and are designed to automatically shut if specific conditions occur. Alerted to the problem by several annunciators, the operators verified that no indications of an actual PSW problem, and overrode the logic and reopened the valves before any problems resulted from the TB PSW being throttled. One of the inspectors was in the CR and observed the operators' response and concluded that the operators took prompt effective actions. Subsequently, the appropriate LCO action statement was entered due to the automatic function of the valves being inoperable. The problem was attributed to freezing of the differential pressure instrumentation associated with the valves isolation function. Additional insulation was placed around the differential pressure instrumentation lines.

During tours of the lower elevations of the main stack, the inspectors noted that the filter unit for the sampling pump on the "B" normal stack monitoring system was installed in such a manner that any accumulated moisture in the jar would drain into the sampling system. The inspectors noted that instructions on the glass container portion of the filter stated that some routine maintenance was periodically required. The inspectors could not locate maintenance procedures that address the filters. The inspectors could not locate any technical instructions regarding these filter units so their function is not clear. The inspectors noted that a similar filter unit on the Unit 1 Fission Product Monitoring system had what appeared to be mold on the felt material inside it. At the close of the report period, the licensee was investigating the filter units and any controls that may be required. The inspectors will monitor this issue.

Early in the inspection period, the inspectors had noted conditions of poor housekeeping in the area of the stack monitoring system. During tours conducted several days later, it was noted that the area had been substantially cleaned.

No other significant deficiencies were noted.

b. Inoperability of Main Stack Radiation Monitoring System

During a tour of the CR on January 25, one of the inspectors noted that a portion of the "A" channel of the "normal" main stack radiation monitoring instrumentation had been removed from the CR panel for corrective maintenance. The channel had failed calibration earlier. This rendered both of the stack radiation monitors inoperable. The Unit 1 SS was aware of this and an LCO had been entered.

Table 3-1 of the ODCM contains the operability requirements for the radioactive gaseous effluent monitoring instrumentation. Items 3.a to 3.e addressed the main stack monitoring system. Loss of the normal stack monitors effected the following instrumentation: noble gas activity monitor (item 3.a), iodine sampler cartridge (item 3.b), particulate sampler filter (item 3.c), and sampler flowrate measurement device (item 3.e). The SS stated that operation of the main stack Kamen system fulfilled the action statement requirements of the ODCM table. The Kamen system is a post accident monitoring system which automatically starts on normal monitoring problems or high radiation levels. The inspector questioned the ability of the Kamen to meet the minimum detectable concentration listed in the ODCM as required of a noble gas activity monitor. The SS immediately contacted the laboratory foreman and was informed that the Kamen did not fulfill the noble gas monitor requirement. However, daily sampling as required by the ODCM action statement (if no noble gas monitors are operable), was planned. The SS revised the LCO sheet to reflect the sampling requirement. The inspector verified that the laboratory personnel had been aware of the sampling requirement from the time they had been informed the normal monitors were inoperable.

At about 3:30 pm on January 25, the inspector examined the stack Kamen in order to verify the ODCM action statements were being met. The inspector noted that although the system appeared to be running properly, an "equipment failure" indication was lit on the Kamen panel. The alarm could have indicated an abnormal system condition. Since action 104 of ODCM Table 3-1 (sampler flowrate measurement device) was being fulfilled by the Kamen, the inspector requested verification that the system flowrate was appropriate. Subsequently, I&C personnel cleared the alarm and verified that the Kamen was operating properly. The inspector was informed that the Kamen alarm remains lit after the Kamen starts until it is reset.

During a tour of the main stack on January 26, the inspector noted that the "B" normal stack monitor sample pump (1D11-C005B) had become inoperable. Repair Tag 07356 had been written to address the problem. Subsequent discussions indicated that laboratory personnel had apparently not been promptly informed of the actuation of the Kamen system. Actuation of the post accident monitoring system isolates the suction to the normal monitoring system sample pumps. The sample pumps continue to operate unless manually secured. The "B" pump subsequently became inoperable due to continued operation without an open suction path. Since the Kamen system had been initiated by a planned maintenance activity, the inspector concluded that the loss of the sample pump was unnecessary. Additionally, the inspector noted that the sample flowrate for the normal stack monitoring system was oscillating between 0 and 1.0 scfm, which is below the required 1.0 to 3.8 scfm required. The laboratory foreman was informed and the flowrate was adjusted.

The inspectors concluded that the requirements of the ODCM for the inoperable stack monitoring system had been met in that the Kamen system started and operated as required. However, concerns were noted regarding the poor communications and inadequate coordination between the involved work groups. Since the Kamen system was being relied upon to meet effluent monitoring requirements, the equipment failure alarm should have been investigated and reset earlier. The alarm could have been indicative of an inoperable Kamen system. There are no CR alarms associated with improper Kamen flowrate and other malfunctions which may occur. Better coordination would have most likely prevented the failure of the "B" normal sample pump. The inspectors noted that CR procedures do not require notification of I&C personnel on a Kamen system actuation. The procedures also do not require verification that the Kamen is operating properly after startup. These concerns were communicated to management and corrective actions were initiated.

3. Surveillance Testing (61726)

a. Surveillance Observations

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

The following surveillances were reviewed and witnessed in whole or in part:

1. 42CC-ERP-022-0S: Use of Flux Tilt to Find Failed Fuel

2. 34SV-E41-002-2S: HPCI Operability Test

3. 42SV-R42-007-0S: Battery Charger Capacity Test

4. 34SV-E41-002-1S: HPCI Operability Test

5. 34SV-P41-001-1S: Plant Service Water Pump Operability

During one backshift tour, sampling of the offgas system was observed. An attempt to identify a possible increase in Unit 2 fuel leakage was in progress. During sampling of offgas pretreatment lines, the inspector observed that the technician had the procedure in hand and referred to it as necessary during the sampling evolution. Good attention to detail was noted regarding compliance with the steps in the procedure.

The Battery Charger Capacity Test was performed on 3 chargers, 2R42-5026, 5027, 5028, which supply power to Station Service Battery 2A and 3R22-5016, 250V DC Battery Switchgear 2A. This Unit 2 Surveillance was required to be performed once per 18 months. The Station Service Battery Charger Capacity Test required that the charger, for a four hour duration, supply a minimum of 400 amps at a minimum of 129 volts. The tests were completed satisfactorily.

b. HPCI Testing Observations

During the observation of the Unit 2 HPCI testing on January 10, the inspector noted that personnel in the HPCI room were well prepared, frequently referred to the surveillance procedure, and properly obtained the required vibration readings. Some small debris was noted in the leakage drainoff area around the turbine. The inspector noted that several hardhats and a piece of plastic were located in the pit containing the instrumented sump isolation valve. Neither of these issues involved safety system operability. The materials were removed and the areas were cleaned up shortly after the testing was completed. The inspector identified a small packing leak (steam) on valve 2E41-F029 (HPCI steam supply line drain valve) which had not been addressed with a repair tag. The system engineer was informed of the leak. On January 12, MWO 2-94-0082 was initiated which requested that the packing be adjusted during the next HPCI test. The inspector also noted that communications between the HPCI room and the control room relied on the use of the installed phone system. During operation of HPCI, high noise levels make communications difficult. During other HPCI tests, the inspectors have noted examples in which the CR personnel could not readily contact the personnel in the HPCI room. During this test, personnel in the HPCI room did not use improved communications equipment which had been made available for such testing. The inspector also observed that personnel utilized low dose areas within the room as appropriate to maintain exposure ALARA.

During observation of the Unit 1 HPCI surveillance testing on February 1, 1994, the inspector noted communications problems. In addition to the issue of high ambient noise levels, the telephone in the HPCI room was not functioning properly. Operations management is reviewing the overall issue of communications during HPCI testing. In preparation for the Unit 1 HPCI test, the hydrogen injection rate was reduced from 35 scfm to 20 scfm. During previous HPCI tests, the flowrate has been reduced to between 8 to 12 scfm. The inspector noted that the HPCI room dose rates during operation of HPCI were approximately double the typical dose rates. The lowest dose rate on the turbine elevation was about 40 mr/hr. The inspector noted that HP coverage of the test was appropriate and personnel utilized low dose areas when possible. Management is reviewing the dose information to determine the best hydrogen injection flowrate during testing. During the testing, the inspector noted several minor equipment discrepancies which were forwarded to the system engineer for resolution. A bearing low oil pressure alarm actuated during the test. One of the inspectors was in the CR and noted that the operators complied with the alarm response procedure and monitored temperatures as required. Subsequently, maintenance personnel adjusted the oil pressures and the alarm condition cleared. The inspectors verified that the oil pressure adjustments were performed in accordance with an approved procedure. After reviewing maintenance records and discussing the oil pressure issue with the HPCI system engineer, the inspectors concluded that adjustment of the oil pressures during a routine surveillance test is a very infrequent evolution.

While no safety significant deficiencies were noted during the observed testing, the inspectors will monitor the licensee's actions regarding the communications problems and high dose rates during the HPCI testing. The HPCI system engineer was particularly responsive in addressing the inspector's concerns following each of the tests.

c. Gaseous Effluent Radiation Monitor Issues

The inspectors reviewed a sampling of the licensee's controls associated with the Unit 2 offgas system post treatment radiation monitors (1, 2D11-K615A and K615B) and other effluent monitoring systems. Calibration of several of the detectors and monitors, setpoint calculations, and other testing procedures were reviewed in detail. The procedures were compared to the requirements in TS and the ODCM, and the FSAR descriptions and data from completed testing were also reviewed. Numerous discussions were held with chemistry technicians, foremen and supervisors.

The daily channel checks of many of the instruments required by TS Table 4.3.6.1-1 was included in procedure 34SV-SUV-019-2S: Surveillance Checks, which is completed by the CR operators. The inspectors reviewed the channel readings and verified that the acceptance criteria of the procedure was met. Chemistry personnel perform the attachments of 62EV-SAM-003-0S: Gaseous Waste Discharge Monitor Checks, on a daily basis. This required recording of the channel indications, sample flowrate, vacuum, and offgas flow rate. The acceptance criteria addresses only sample flow and vacuum. The inspectors noted that the Unit 1 offgas posttreatment channels differed significantly. For example, in the month of October, the "A" channel indicated about 76 cps while the "B" channel indicated about 130 cps. Additionally, the inspectors noted that the background indication on one channel was 6 cps while the other channel background was approximately 44 cps. Since the detectors are located in the same location with the same gas flowing through them, it was not clear why the backgrounds would be so different. Discussions with chemistry personnel indicated that this issue had been examined in the past. The background levels had been confirmed and could not be reduced. The inspector reviewed MWOs dated in February 1990, and March 1991, which documented unsuccessful efforts to reduce or determine the cause of the different background levels. The inspectors also noted that while section 7.7 of procedure 62CI-CAL-007-0S: Offgas Vent Pipe Monitor and Posttreatment Monitor, described the method for determining system background, there were no procedural guidance on when to determine or verify the backgrounds.

Other effluent testing requirements are met with a combination of I&C and Chemistry procedures. The inspector reviewed the calculations for numerous setpoints and then verified that the actual setpoints on the CR equipment matched the calculated values. Additionally, the release curves maintained in the CR were verified to contain the most recent calibration factor and setpoints. The curve for one monitor incorrectly listed the high-high-high setpoint as 5.00E 5. The correct setpoint was 2.99E 5. The computer which is used to develop the release curve plots automatically inserts the 5.00E 5 value on the curves. This minor discrepancy was reported to the laboratory foreman. The inspector noted that procedure 62CI-CAL-007-0S: Offgas Stack Monitor and Posttreatment Monitor, made reference to TS limits which have been relocated to the ODCM. The inspector's review of some of the requirements indicated that the actual requirements have not changed, only their location.

The inspector noted that the licensee's processes rely heavily on the experience of the chemistry technicians and foremen. A routine "task sheet" posted in the laboratory is used to ensure that required evolutions are performed. The associated procedures and record keeping methods were often difficult to follow.

The inspector noted that procedure 42SV-N62-001-1S: Steam Jet Air Ejector Offgas Line Isolation LSFT, verified that valve 1N62-F527 (main stack inlet valve) shuts on the appropriate posttreatment monitor signal. The identical valve on Unit 2 (2N62-F057) is not tested. Unit 1 TS Table 4.2-8 specifically required the isolation of 1N62-F527 to be tested. Unit 2 TSs do not contain a specific requirement. Unit 2 FSAR section 11.4.2 discusses the isolation function of the F057 valve on a high posttreatment signal. The inspector also noted that Unit 2 TS 4.3.6.1-1 required that the posttreatment radiation monitor channels be calibrated and functionally tested. The definition of a channel functional test in the Unit 2 TS states that the functional test is to be the injection of a simulated signal into the channel sensor to verify operability including alarm and/or trip functions. The inspector determined that procedure 57SV-D11-006-2S: Offgas Posttreatment Radiation Monitor Functional Test, tests the channels from the sensors to the relay which actuates the valve. Discussions with the system engineer verified that the isolation function of the valve is not tested. A review of maintenance records did not identify any recent maintenance on the valve. The inspector did not identify any safety related role of the isolation of the valve. The inspector noted that the proposed standard BWR 4 TS will not require testing of the valve.

During review of procedure 62EV-SAM-003-0S: Gaseous Waste Discharge Monitor Checks, the inspector identified a deficiency. Step 7.1.3.1 required that after determination of the acceptable calibration factor or "K" factor for a monitoring system, chemistry personnel are to provide emergency preparedness personnel with the acceptable calibration factors. The inspector verified that several of the calibration factors, as recorded on the chemistry laboratory data sheet, matched the calculated factors. The inspector contacted EP personnel and requested a listing of the calibration factors currently installed in the offsite dose projection program with the intent of comparing the values to those in the laboratory database. The EP personnel determined that the factors installed in the dose projection program did not match the laboratory values.

On January 1, 1994 Hatch implemented the use of the MIDAS (Meteorological Information and Dispersion Assessment System) program to calculate offsite dose projections. For prompt dose assessment and calculation to determine if a release is in progress, the program is run on a desktop computer at the STA workstation. In accordance with 73EP-EIP-018-0S: Prompt Offsite Dose Assessment, meteorological data and radiation monitor readings are input into the program and CDE and TEDE are generated. Since the calibration factors are direct multipliers in the dose assessment process, the use of incorrect values could result in inaccurate offsite dose projections. The inspector noted that one calibration factor varied from the calculated calibration factor by a factor of 30.

Prior to 1994, the licensee used the MESORAD program installed in SPDS to provide prompt offsite dose assessments. EP personnel determined that some of the calibration factors installed in that program were also inconsistent with the laboratory database. If SPDS was not available, the operators would use the release curves maintained in the CR to calculate the dose. The curves had been maintained current in accordance with chemistry procedures. The calibration numbers are also still used in the SPDS programs to calculate continuously displayed release values.

Followup review by the licensee determined that several years ago chemistry had performed detailed testing to develop accurate calibration factors for the monitoring systems. Some of the calibration factors used in the EP programs discussed above did not match these factors. After some investigation, the licensee revised some of the calibration factors in the MIDAS program to more conservative values. At the close of this report period, the licensee was continuing to investigate the issue. Further review is necessary in order to determine what values should be used in the programs. The inspector noted that in some accident scenarios, the high range monitoring equipment would be operational (normal range monitors would be upscale) and would be used to obtain data for dose assessment. The calibration factors for this equipment are determined and used in a different manner, and dose projections calculated from high range monitor data would not use or incorporate incorrect calibration factors.

The inspectors concluded that the Emergency Preparedness applications of radiation monitor calibration factors were not being appropriately controlled. Additional detailed review will be necessary to determine the safety significance of the issue. This issue is identified as Unresolved Item 50-321,366/94-02-01: Inadequate Controls Regarding Radiation Monitoring Systems Calibration Factors.

One Unresolved Item was identified.

4. Maintenance Activities (62703)

a. Maintenance Observations

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

The following maintenance activities were reviewed and witnessed in whole or in part:

1.	MWO 1-93-5756	1D11-K619 Reactor Building Vent Stack Radiation Monitor B Spiking
2.	MWO 1-93-887	Remove Cell Number 55 and Replace with New Cell, EDG 1A Battery
3.	MWO 1-94-126	Chip and Excavate Concrete to Allow Access to Conduits for Inspection of Damage
4.	MWO 2-94-153	MPL 2R42-S002A, EDG Battery 2A
5.	MWO 1-94-1015	MPL 1R42-S001B, Station Service Battery 1B
6.	MWO 2-94-0315	Repairs to SBGT Control Wiring (2T46-D001B)

The inspectors observed the activities involved with the replacement of battery cell 55 of the 1A DG battery. During a walkdown of the battery the system engineer noted that the positive plate of the cell had expanded. This expansion was beyond what would be expected of a cell at the three year life. A decision was made to replace the cell while still within manufacturers warranty. The inspector performed an independent walkdown of the other cells in the Hatch DG battery systems and did not note any similar deficiencies. All work activities were performed in accordance with procedure, QC verified the torque valves used to install the battery, reassembly of the rack was correct, and maintenance supervision was present at the job site.

The inspectors observed and reviewed some of the maintenance activities involved with the RCIC system. These activities were controlled by several MWOs such as: 1-93-4152, Repack Valve 1E51-F127 (turbine bypass line isolation); 1-93-5394, VOTES Test of Valve 1E51-F019 (minimum flow bypass valve); and 1-93-4123, RCIC Turbine Controls. All activities were performed in a controlled manner using approved processes. The inspector observed the use of procedures 51IT-CAL-002-1S: RCIC Turbine Control, and 57CP-CAL-245-1S: Calibration of HPIC/RCIC Turbine Controls Performance Monitoring Equipment, in conjunction with MWO 1-93-4123. The RCIC turbine underwent post maintenance testing on January 25 and 26, 1994.

b. Underground Cables Damaged During Maintenance Activities

During a recent operations review, the licensee noted that the fire main pressure was not being maintained at the expected pressure. The licensee discovered a leak in a buried pipe coupling in the area of the auxiliary boiler. During the excavation, a concrete structure was discovered under the buried pipe near the leaking coupling and the pipe concrete thrust block. The workers contacted engineering and were informed that the concrete structure was a support for the pipe. The workers proceeded to use jack hammers to remove a portion of the support. During this activity, the jack hammer unexpectedly penetrated through several cable conduits and damaged the associated cables. The workers stopped hammering immediately after the problem occurred. Control room operators noted that some fuses were blown in CR panel P600, Offgas Control Panel. The fuses were later identified as being in the circuit for valve 1N62-F025B, Inlet Valve to Cooler Condenser 1N62-B003B; valve 1N62-F030B; and loop seal valve for cooler condenser 1N62-B003B. Also identified as damaged was the output of PT-1N62-N012, Glycol Pumps Discharge Pressure to PI-1N62-R605.

The inspectors reviewed drawings H-16532 and H-16563. The review indicated that valve 1N62-F025B is a remotely operated air solenoid valve, valve 1N62-F030B is a remotely operated air solenoid valve with a trip function from the process radiation monitoring system, and PI 1N62-R605 provides remote indication on the offgas control panel. The inspector also observed the status of Unit 1 CR Panel P600 and noted that the following items were tagged with repair tags: valve 1N62-F025B, glycol pump pressure indicator, the temperature indication for absorber vessel D013B, prefilter differential pressure indicator R611, and glycol storage tank temperature indicator R606.

The result of the damage was the degradation of the offgas system, a system important to safety. This degradation mainly involved the inoperability of one of two cooler condenser moisture separators in the offgas system.

The inspector observed subsequent jack hammer activities that were conducted to expose the damaged conduits and noted that the activities were being closely monitored by supervisors. Three conduits and their associated electrical cables had been damaged. Additionally, the inspector observed the licensee's signal tracing activities on the electrical cables in order to identify the extent of the damage. The inspector reviewed the results and noted the following concerning the cables in the upper conduit:

CABLE NO.	DAMAGE
SPR 770	Outer protective jacket damage
1H11P700/A1022	Outer protective jacket damaged, conductor insulation damaged and bare conductors visible.

N62P600C001	Outer protective jacket damaged, conductor insulation damaged and bare conductors visible.
N62P600C009	No apparent damage
N62P600C012	Completely severed
N62P600C021	Outer protective jacket damaged, conductor shield damaged, conductor insulation damaged, and bare conductors visible.
N62P600C027	Completely severed

The inspectors also noted that a relatively large cable (not yet identified), located in the middle conduit, appeared to be damaged. The inspector reviewed site procedures to identify the process governing the activities involved in excavating and requesting engineering assistance. Procedure DI-ENG-01-018N: Processing Requests for Engineering Review/Assistance, was specifically reviewed by the inspector. It was noted this procedure was to be used when it is only desired to obtain clarification of some technical question so that proper subsequent actions may be taken. The inspector determined, had the RER process been initiated and followed, the resultant damage most probably would not have occurred. The failure of engineering support to perform a more rigorous review regarding the excavation, was considered a major contributor to the resulting damage. Although it is difficult and requires dedicated effort, it is possible to determine what equipment is underground in a specific location. Additionally, it was noted that maintenance personnel did not stop jack hammering and request more engineering assistance when reinforcing bars were unexpectedly encountered.

The inspector concluded that these activities were examples of poor work practices, work supervision and engineering support. No specific violations of regulatory requirements were identified. While the cabling damage involved a low level of safety significance, the lack of proper coordination and review over the excavation activities resulted in damage to an important plant system. Additionally, the workers could have been injured by contact with energized cabling. The licensee initiated corrective actions. The designation of excavation coordinators, one of which must be on hand during excavation activities, was completed. The inspectors discussed with one of these coordinators his areas of responsibility. The coordinator indicated that being present at the job site, review of appropriate drawings, and verifying the location of underground components were his major duties.

5. ESF System Walkdown (71710)

The inspectors conducted a walkdown of the Unit 2 CS and RHRSW system. Valve, switch, and electrical board lineups in the CR and locally were verified to ensure the lineups were in accordance with operability requirements. Walkdowns of spaces were performed to verify equipment conditions, housekeeping and cleanliness. Various piping supports and hangers, instrument valve alignments, and other support systems were verified to be operable.

In preparation for the inspection a review of the applicable sections of the FSAR, TS, P&IDs and the instrument setpoint index were conducted. Also, various operating, maintenance and surveillance procedures were reviewed. The inspectors also conducted a work history review of various system components and instruments.

During this review the inspectors verified that the surveillances were completed on time, and that the procedure acceptance criteria was in accordance with the instrument setpoint documents and TS. Valve stroke times during an emergency were verified to be as required by the FSAR and TS. Various alarm response procedures were verified to have conservative setpoints. The inspectors also reviewed the lubrication procedures to verify the proper lubricants were being used.

The inspectors did not identify any safety significant issues that would affect system operability. However, during the system walkdown the inspectors identified two air line leaks. One leak involved the quadrant area flood protection isolation valve and the other leak involved a RHR system valve. These minor discrepancies were discussed with licensee personnel. One had been identified previously by the licensee. The inspectors concluded that the instrument setpoint, calibration and surveillance programs were well developed, implemented and documented. The surveillance procedures were conducted on time and the acceptance criteria were as required by the instrument setpoint documents, FSAR and TS. The past history review of MWOs and DCs did not identify any generic maintenance problems.

No violations or deviations were identified.

6. Iodine Monitoring Program Deficiencies (71707)

The inspectors reviewed portions of the licensee's post accident iodine monitoring program. TS 6.14 (Units 1 and 2) require that the licensee implement a program to ensure the capability to accurately determine the airborne iodine concentration in certain vital areas under accident conditions. The program is required to include training of personnel, procedures, and provisions for equipment maintenance. The iodine monitoring program is a Three Mile Island Lessons Learned Category "A" Requirement, which was incorporated into the Hatch TSs on September 15, 1980.

During examination of the sampling equipment maintained at the OSC, two deficiencies were noted. The silver zeolite cartridges required for sampling were older than the five year shelf life indicated in the procedure. Procedure 62RP-RAD-034-0S: Emergency Air Sampling Program, was not available in the OSC procedure files. The inspector observed that a low-volume air sampler (appropriately configured, labeled, and tested) was available. The other equipment associated with iodine sampling was also available.

Silver zeolite cartridges are used for post accident measurement of radioactive iodine because while their retention for radioiodine is high, they will not retain significant amounts of noble gases. The large amounts of noble gases which would be retained in a charcoal cartridge would interfere with accurate iodine measurement. The inspector noted that limitation 5.2, of procedure 62RP-RAD-034-0S, stated that the silver zeolite cartridges have a shelf-life of five years. The cartridges in the OSC storage area were in a box clearly labeled with a manufacture date of October 1987. EP personnel were informed of the issue. It was determined that the silver zeolite cartridges in the EOF storage were most likely older than five years. Corrective actions were initiated. On January 17, new cartridges were obtained and placed in the OSC and EOF areas. In response to the inspector's questioning, chemistry department supervisors verified that the other applications of silver zeolite cartridges at Hatch were not beyond their shelf life. Several of the cartridges which were older than five years have been sent back to the vendor. The vendor is to examine and assess their ability to perform their function. EP personnel have initiated procedural revisions such that verification of a shelf life is required on the cartridges during the periodic inventories of the emergency facilities.

The inspector also noted that procedure 62RP-RAD-034-0S: Emergency Air Sampling Program, was not located in the OSC procedural files. This procedure provides instructions for obtaining air samples and directs the technicians to other specific procedures for analysis of the samples. The inspector concluded that it would be appropriate for the procedure to be readily available. While the procedure would be available in document control files which are adjacent to the OSC, it was not clear how the technicians would be directed to use the procedure. Discussions with several HP technicians indicated that training and periodic exercises had familiarized them with the sampling equipment and requirements. The inspector noted that procedure 73EP-EIP-014-0S: Internal Survey Team Duties, lists 62RP-RAD-034-0S as a reference but does not direct its use. Corrective actions were initiated to include the procedure in the OSC and EOF procedure files.

The failure to ensure that iodine sampling equipment was properly maintained is a violation of TS 6.14. Because the shelf life of the cartridges was exceeded by only 15 months and the cartridges were stored in a controlled environment and in plastic bags, it is expected that the cartridges would have been able to fulfill their function during accident conditions. This NRC identified violation is not being cited because criteria specified in Section VII.B of the NRC Enforcement Policy were satisfied. In accordance with Supplement VIII of the Enforcement Policy, this issue is considered a violation that has minor safety significance. As discussed above, corrective actions were completed promptly. This issue is identified as NCV 50-321,366/94-02-02: Iodine Monitoring Program Deficiencies.

One NCV was identified.

7. Visit to Local Public Document Room

On January 19, 1993 the inspectors visited the local PDR at the Appling County Library in Baxley, Georgia. The inspectors familiarized themselves with the arrangement of documents within the PDR and the types of documents available for public review. A review of Hatch FSARs, LERs, Hatch Inspection Reports, NRC Bulletins and INs showed that the files were current.

The inspectors reviewed a recent IR and LER and verified that the NUDOCS users guide was correct and user friendly. The microfiche reader was in good condition and operated correctly. The microfiche files were up to date. The librarian indicated that the PDR was used very little. The inspectors concluded that the PDR was organized and well maintained. The facility is adequate to meet local needs for information regarding Plant Hatch.

No violations or deviations were identified.

8. Inspection of Open Items (92700) (92701)

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

a. (Closed) LER 50-321/92-02: Personnel Errors Results in Missed TS Surveillances. This LER addressed an incident involving instrument checks on suppression chamber water temperature and the APRM indicators. A discussion of the incident was documented in IR 50-321,366/92-02. The inspectors initiated IFI 50-321,366/92-02-02: Improper Use of the Editorial Correction Process, in part, due to this incident. The IFI was closed in IR 50-321,366/93-03. The inspector reviewed procedure 34SV-SUV-019-1S and noted that both the suppression chamber and the APRM instrument checks were required to be performed daily. Based on the closure of the IFI, and this review of the procedure this LER is closed.

b. (Closed) IFI 50-321/92-32-03: Intake Traveling Water Screen Issues. This item was identified during a plant tour by the inspectors and was discussed in detail in IR 50-321,366/92-32. The inspectors concern involved the large amount of leaves that were picked up by the traveling screens. The leaves spilled over into the service water pump suction bays and clogged up the screen wash discharger flow trough. The licensee emphasized to the operators how the screen wash system functions, the need to be more observant when doing outside rounds, to monitor the screen wash operation, and to insure that the system was functional. Based on the licensee's activities this IFI is closed.

c. (Closed) LER 50-321/93-02: Safety Relief Valve Setpoint Drift. This voluntary LER documented the SRV setpoint drift in excess of the 3% tolerance specified by the IST requirements. The cause of the drift was corrosion induced bonding of the pilot valve disc and seat. The licensee had been participating in the BWROG efforts to resolve the SRV setpoint issue. A plant modification was installed to provide redundant electrical actuation signals to the SRVs such that the corrosion bonding issue is not a factor in the valve not lifting within the TS setpoints. This item is closed.

d. (Closed) LER 50-366/93-05: Personnel Error Results in a Condition Prohibited by TS. This LER addressed an occurrence when, due to personnel error, power level exceeded 40% during CRD scram time testings. Details of the event are discussed in IR 50-321,366/93-05. A violation was issued in the IR and closed in this report. Based on the licensee's activities reviewed during the closeout of the violation, this LER is closed.

e. (Closed) Violation 50-321,366/93-05-01: Examples of Failure to Follow Procedure. This violation documented two examples of failure to follow procedure. The examples were discussed in IR 50-321,366/93-05. The inspector reviewed the licensee's response, dated May 28, 1993. The response to example one stated that the guidelines issued by the Manager PM and MS would be incorporated into procedure 52PM-R22-001-0S, 4160 Volt AC switchgear and Associated Electrical Components Preventive Maintenance. The inspector reviewed the procedure and noted that section 7.6, Switchgear Preventive Maintenance, required the testing for the presence of voltage and stated that maintenance was to be performed on frames confirmed to be de-energized; and section 6, Prerequisites, subsection 6.3, required the instruction DI-MNT-18-0188N be reviewed by all personnel. The inspector reviewed the instruction and noted that the guidelines discussed in the licensee's response were contained in the instruction. The response to example two stated that the personnel involved would be counseled and procedures would be changed. The inspector reviewed four procedures, 34GO-OPS-001-1S and 2S: Plant Status, affecting both units, and 42SV-C11-001-1S and 2S: Control Rod Scram Testing. The inspector noted that section 7.5, Turbine Generator Startup, Synchronization and Loading, of the plant startup procedures contained instructions directing the operators to perform the rod insertion time testing normally at 35% RTP in order not to exceed 40% RTP. The review of the scram testing procedures indicated that section 6, Prerequisites, of the procedure contained instructions directing the operators not to exceed 40% RTP during rod scram time testing. Based on the license's activities this violation is closed.

f. (Closed) VIO 50-366/93-24-01: Failure to Follow Procedure During HPCI Testing. This violation addressed an event involving a functional test procedure and was discussed in IR 50-321,366/93-24. As part of the corrective action, the licensee provided two, four-hour training sessions, under the direct supervision of operations department supervision, for a licensed operator to demonstrate proficiency in performing plant surveillance procedures. The training was performed using the plant specific simulator. Based on a discussion with the operations personnel who supervised the training and the stated results of the training session, this violation is closed.

8. Exit Interview

The inspection scope and findings were summarized on February 14, 1994, with those persons indicated in paragraph 1 above. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

Item Number	Status	Description and Reference
321,366/94-02-01	Open	URI - Inadequate Controls Regarding Radiation Monitoring Systems Calibration Factors, paragraph 3c.
321,366/94-02-02	Open	NCV - Iodine Monitoring Program Deficiencies, paragraph 6.

9. Acronyms and Abbreviations

AC - Alternating Current
APRM - Average Power Range Monitor
ATTS - Analog Transmitter Trip System
BWR - Boiling Water Reactor
BWROG- Boiling Water Reactors Owners Group
CAD - Containment Atmospheric Dilution
CDE - Committed Dose Equivalent
CFR - Code of Federal Regulations
cps - Counts Per Second
CR - Control Room
CS - Containment Spray
CST - Condensate Storage Tank
DC - Deficiency Card
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EOF - Emergency Operations Facility
EP - Emergency Preparedness
ESF - Engineered Safety Feature
°F - Fahrenheit
FSAR - Final Safety Analysis Report

GE - General Electric Company
HP - Health Physics
HPCI - High Pressure Coolant Injection System
I&C - Instrumentation and Controls
IFI - Inspector Followup Item
IN - Information Notice
IR - Inspection Report
IST - Inservice Test
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LSFT - Logic System Functional Test
mr/hr- millirem per hour
MWO - Maintenance Work Order
NCV - Noncited Violation
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
ODCM - Offsite Dose Calculation Manual
OSC - Operations Support Center
PDR - Public Document Room
P&ID - Piping and Instrumentation Drawing
PM - Preventive Maintenance
PSW - Plant Service Water System
QC - Quality Control
RCIC - Reactor Core Isolation Cooling System
RER - Request for Engineering Review
RH - Relative Humidity
RHR - Residual Heat Removal
RHRSW- Residual Heat Removal Service Water System
RTP - Rated Thermal Power
SBGT - Standby Gas Treatment
scfm - Standard Cubic Feet Per Minute
SCS - Southern Company Services
SOS - Superintendent of Shift (Operations)
SPDS - Safety Parameter Display System
SRV - Safety Relief Valve
SS - Shift Supervisor
STA - Shift Technical Advisor
TB - Turbine Building
TEDE - Total Effective Dose Equivalent
TS - Technical Specifications
URI - Unresolved Item
V - Volts