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

Report Nos.: 50-321/92-32 and 50-366/92-32

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: November 8 - December 5, 1992

Inspectors:	Leonard D. Wert, Jr., Sr. Resident Inspector	12-22-92 Date Signed
	Edward F. Christnot, Resident Inspector	12-22-92 Date Signed
Approved by:	Pierce H. Skinner, Chief, Project Section 3B Division of Reactor Projects	12-22-92 Date Signed

SUMMARY

Scope: This routine, announced inspection involved inspection on-site in the areas of operations, (including review of; reactor vessel shroud support access hole cover operating guidelines implementation a unit 2 scram, and intake screen wash system problems), surveillance testing, (including standby liquid control system testing), maintenance activities, controls on overtime, and review of open items.

Results: Two non-cited violations and one inspector followup item were identified:

The first non-cited violation addressed a deficiency identified by the inspectors. The 1A standby liquid control pump was rotating in the reverse direction. The pump is a positive displacement pump and inadequate lubrication over extremely long operating times is the only potential operational problem. The licensee did not properly utilize information provided in Information Notice 91-27 addressing this issue. The inspectors noted another discrepancy involving test methodology during observation of standby liquid control system testing (NCV 321/92-32-01: Incorrect Standby Liquid Control Pump Rotation, paragraph 3b).

The second non-cited violation involved two examples of unauthorized deviations of hourly overtime limits by health

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physics personnel. The issue was identified by the licensee as a result of the overtime monitoring system (NCV 321,366/92-32-02: Unauthorized Deviations of Overtime Limits by HP Personnel, paragraph 5). It was noted that numerous licensed operators had worked significant overtime hours in support of the Unit 2 refueling outage. A discrepancy involving contract HP shift hours was corrected. The inspectors concluded that significant management attention and monitoring efforts were being applied and that the overall control of overtime hours met the regulatory requirements.

The inspector followup item addressed deficiencies identified involving the intake structure traveling water screen system. The inspectors followup review of a problem noted in Inspection Report 321,366/92-29 identified that improvements are needed regarding the operation and monitoring of the system. Proper operation of the system is important to ensure that the service water systems are not degraded (IFI 321/92-32-03: Intake Traveling Water Screen Issue, paragraph 2d).

During review of a Unit 2 scram due to high main turbine vibrations the inspectors noted that an annunciator masking problem directly contributed to the scram. A previously actuated feed pump turbine vibration alarm blocked warning of the increasing turbine vibrations by an annunciator.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *J. Betsill, Unit 2 Operations Superintendent
   C. Coggin, Training and Emergency Preparedness Manager
   D. Davis, Plant Administration Manager
   *P. Fornel, Maintenance Manager
   *O. Fraser, Safety Audit and Engineering Review Supervisor
   *G. Goode, Engineering Support Manager
   J. Hammonds, Regulatory Compliance Supervisor
   *W. Kirkley, Health Physics and Chemistry Manager
   *J. Lewis, Operations Manager
   C. Moore, Assistant General Manager - Plant Support
   *D. Read, Assistant General Manager - Plant Operations
   *P. Roberts, Acting Outages and Planning Manager
   *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, Unit 1 Operations Superintendent

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

   NRC Resident Inspectors

   *L. Wert
   *E. Christnot

   * Attended exit interview

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

2. Plant Operations (71707) (92701) (92720)

   a. Operational Status

      Unit 1 operated at full rated power for most of the report period. Power was reduced to 680 MWE at 8:00 a.m. November 28, because the number 4 turbine control valve drifted closed. Subsequent investigation indicated that the valve servo strainer was clogged. The servo strainers on all of the TCVs were subsequently changed out. The strainers appeared to be partially clogged with a foreign material similar to conditions noted after a previous Unit 1 scram. LER 321/92-14 and Inspection Report 321,366/92-12 discuss that scram and the identified cause in detail. The unit was returned to full power at 5:42 p.m. on November 28. On December 3, after the "A" EHC pump discharge filter indicated a

high differential pressure, it was replaced. On December 4, the four turbine stop valve servo strainers were replaced. At the close of this report, the cause of the material in the strainers had not been determined. Later on December 4, power was reduced to about 88 percent for several hours to complete a planned rod sequence exchange.

On November 19, 1992, at approximately 4:00 a.m. EST, a Unit 2 reactor startup was initiated following the tenth refueling outage. The inspectors closely monitored the initial portions of the startup including rod withdrawal to criticality. The startup progressed in accordance with procedures and the generator was tied to the grid at approximately 7:00 p.m. on November 21, 1992. Power ascension to 100 percent was performed in several stages, with various post modification tests surveillances and equipment checks performed at each power or pressure level. The inspectors periodically observed the post modification functional testing for DCR 90-163 (procedure 17SP-111192-PO-1-2S). This included dynamic testing of the feed water system. The test was performed to check the new digital feed water controllers installed during the outage. The operators had increased reactor power to 95 percent, when on the evening of November 24, 1992, a significant EHC fluid leak was discovered on the number 4 CIV cylinder operator. The generator load was reduced and the generator taken off the line at approximately 8:45 p.m. The leak was caused by a failed "O" ring. The "O" ring was replaced and power ascension was resumed.

At approximately 3:34 a.m. on November 27, 1992, the reactor scrammed due to a turbine trip. The turbine trip was initiated by high turbine vibrations. Paragraph 2c of this report contains additional discussion of the scram. The high turbine vibration was attributed to loading the turbine at a rate which did not allow for proper warming. To improve heat rate performance, the main turbine control valve logic had been changed to a "modified" partial arc admission scheme during the outage. This apparently changed some of the performance characteristics of the turbine. A startup was commenced early on November 28 and the unit was returned to full rated power at 3:46 p.m. on November 30.

On December 2, it was noted that the main generator hydrogen pressure was decreasing. By December 3, the cause had been traced to a leak on a generator neutral bushing. At 8:25 on December 5, power was decreased to 600 MWE in an attempt to reduce the hydrogen leakage by reducing hydrogen pressure required in the generator. At 10:48 p.m. a reactor shutdown was initiated to remove the turbine from service to repair the leak.

The inspectors reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, Technical Specifications, and administrative controls. Control room logs, shift turnover records, temporary modification logs, LCO logs and equipment clearance records were reviewed routinely.

Discussions were conducted with plant operations, maintenance, chemistry, health physics, instrumentation and control, and nuclear safety and compliance personnel. The inspectors also periodically monitored the ongoing SFP cleanup project.

Activities within the control rooms were monitored on an almost daily basis. 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 Safety Parameter Display system 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. Many of the Unit 2 startup activities were closely monitored. Numerous informal discussions were conducted with the operators and their supervisors. Some inspections were made during shift change in order to evaluate shift turnover performance. Actions observed were conducted as required by the licensee's administrative procedures. The complement of licensed personnel on each shift met or exceeded the requirements of TS. Paragraph 5 of this report discusses a review of overtime controls.

One of the inspectors attended training sessions that addressed design changes completed during the Unit 2 refueling outage which were provided to operations personnel prior to startup. All significant plant changes that the inspectors were aware of were discussed. Particular emphasis was placed on the hardened vent modification and operation of the improved feedwater and recirculation controllers. Additionally, the inspector attended functional training on the improved controllers which was performed in the simulator. The inspector concluded that the training adequately informed the operators of pertinent equipment changes. Several of the modifications were reviewed to verify that necessary procedural changes had been implemented. All required changes were in place.

Several active safety-related equipment clearances were reviewed to confirm that they were properly prepared and executed. Applicable circuit breakers, switches, and valves were walked down to verify that clearance tags were in place and legible and that equipment was properly positioned. Equipment clearance program requirements are specified in licensee procedure 30AC-OPS-001-0S, "Control of Equipment Clearances and Tags." No discrepancies were identified.

Selected portions of the containment isolation lineup were reviewed to confirm that the lineup was correct. The review involved verification of proper valve positioning, verification

that motor and air-operated valves were not mechanically blocked and that power was available (unless blocking or power removal was required), and inspection of piping upstream of the valves for leakage or leakage paths.

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

Reactor Buildings
Station Yard Zone within the Protected Area
Turbine Building
Intake Building
Diesel Generator Building
Fire Pump Building
Unit 2 Drywell
Transmission Switchyard and Relay House

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

One of the inspectors conducted a tour of the Unit 2 drywell immediately after the operations department drywell closeout procedure (34GO-OPS-028-OS: Drywell Closeout) had been completed. The inspector examined overall housekeeping and material conditions, correct positioning of several key isolation valves, and SRV insulation during the tour. All components examined were in the correct position and appeared operable. The insulation on the SRVs was installed properly. The inspectors removed a number of small hand tools and scaffolding nails found during the tour from the drywell. A significant amount of plastic tie wraps and scaffolding nails, as well as an anti-c rubber bootie was noted in the lower elevation of the drywell. The floor drain screens were in place and not blocked. While some amount of small debris was noted on cable trays and flooring as well as other horizonal surfaces, no conditions were noted which would adversely impact operability of safety systems. The inspector discussed his observations with operations management.

b. Shroud Support Access Hole Cover Operating Guidelines

The inspectors reviewed the licensee's implementation of the GE SIL 462 (Shroud Support Access Hole Cover Cracking) recommended reactor operating guidelines. Inspection Reports 321,366/92-29 and 92-25 discuss the licensee's identification of circumferential indications in one of the Unit 2 AHC during the recent refueling outage. The licensee intends to repair the covers during the next refueling outage (Spring 1993). On October 27, 1992, the Hatch AHC indications were discussed in a meeting involving NRC, GPC, and GE personnel. The licensee's technical basis for operation of the unit for an additional cycle included implementation of the SIL 462 recommendations to provide detection of core bypass flow

if a cover plate separation occurs. SIL 462 was issued in February 1988. It addressed cracking in an AHC and provided inspection recommendations. Supplements and revisions to the SIL have been issued as additional information became available. NRC Information Notice 92-57 was issued in August 1992. Revision 1 to SIL 462, Supplement 2 was issued December 19, 1990 and contains specific "reactor operating guideline" recommendations. These guidelines were intended to be implemented until the initial examination of the AHC was completed and results evaluated. The guideline consists primarily of periodic operational verifications to identify core bypass flow through a cracked AHC, and actions to mitigate a failed AHC if necessary.

The licensee developed special purpose procedure 34SP-102792-BD-1-2S: Core Power Versus Core Flow Periodic Monitoring, to monitor for a failed AHC and to provide instructions for actions if a failure occurs. The STA is required to perform the procedure at least once per day throughout the operating cycles at powers above 10 percent. Additionally the procedure is to be performed at any time the power/flow relationship appears abnormal. The procedure requires trending of specific information relating to core flow and power and provides criteria for supplemental actions. If a possible jet pump failure or AHC failure is identified, 34AB-C51-001-2S: Reactor Power Instabilitics, is entered. Specific monitoring actions are completed with concurrence of on-call management, actions are then taken in accordance with the SIL recommendations to reduce power and shutdown the unit. The procedure contains specific guidance to preclude entry into the region of potential instability during power reduction. The inspectors reviewed the data collected in accordance with the procedure. Discussions with several STAs indicated that they were knowledgeable of the indications of a failed AHC.

The inspector noted that 34SP-102792-BD-1-2S was to be performed only on Unit 2. The Unit 1 AHCs had been inspected previously just as the Unit 2 covers and no cracking or indications had been detected. The indications were identified on the Unit 2 covers as a result of improved inspection capabilities. Although the Unit 1 covers are thicker (2 inches versus 5/8 inches) than the Unit 2 covers, they are also susceptible to cracking. The inspectors discussed this with plant management and questioned if it may be prudent to implement similar monitoring requirements on Unit 1.

c. Unit 2 Reactor Scram on High Turbine Vibration

At 3:34 a.m. on November 27, Unit 2 scrammed from approximately 75 percent rated power. The scram was initiated by a main turbine trip. The cause of the turbine trip was high vibration (greater than 12 mils displacement) on bearing number six. The inspector was informed of the scram and responded to the site. After spending several hours assessing plant conditions the inspector

attended the initial post scram meeting which was held at 7:00 a.m.

At 7:00 a.m., on November 26, the unit was at 18 percent power with the main turbine off the line. Bypass valves were open and repairs were being made to the main turbine generator DC motor driven emergency lubricating oil pump. Plant personnel had previously made a decision not to roll the main turbine generator unit the EBOP was repaired. At approximately 4:00 p.m., repairs to the pump were completed and personnel commenced rolling the main turbine generator. The generator was tied to the grid at 6:47 p.m.. The personnel increased power from 8:40 p.m. to 2:20 a.m. and performed additional startup evaluations as required by the plant procedures. The 2B reactor feed water pump was placed in service at 2:20 a.m. and the reactor scrammed at 3:34 a.m.

As a result of the scram, reactor vessel water level decreased to five inches above instrument zero. Water level was controlled by the feed pumps until the level reached 58 inches at which time the RFPTs tripped. Personnel then shifted to controlling the water level with one feed pump and the CRD pumps. Reactor pressure peaked at approximately 1030 psig and all bypass valves opened to lower and then control pressure. Due to a lack of decay heat, personnel closed the MSIVs at 4:27 a.m. and commenced controlling water level with the CRD pumps and the RWCU system.

During the post scram meeting the involved personnel stated that they knew the reactor scram was caused by a turbine trip. They also stated that they did not immediately know what had caused the turbine trip. The inspector monitored and reviewed additional ERT activities. The reviews indicated that all safety functions operated properly during the transient following the scram. Reactor vessel level and pressure remained within controllable limits by the use of bypass valves and RFPs. The transient did result in a decrease in bottom head drain line temperature of approximately 102 degrees F per hour. The cooldown at greater than 100 degrees F per hour was analyzed as required by Unit 2 Technical Specifications.

The unit had been experiencing problems with the "B" reactor feed pump turbine vibration alarms. The design of the alarms and indicators for vibration levels is such that when excessive vibration is detected by either the feed pumps or the main turbine generator a common alarm is sounded in the control room. Due to the B RFPT vibration alarm being in alarm the excessive vibration alarm from the main turbine generator was masked. A review of the applicable strip chart recorders indicated that approximate 90 minutes before the scram, bearings 5 and 6, located on either side of low pressure turbine number 2, began to indicate above 8 mils displacement. The same bearings reached 10 mils at approximate 40 minutes before the scram and bearing 6 reached 12 mils at 3:34 a.m. causing a turbine trip.

The inspectors concluded from the review and observations that the alarm masking problem discussed above directly contributed to the scram. The operators had not been monitoring the strip chart recorder indicating main turbine generator vibration closely enough for approximately two hours prior to the scram, and were not aware of the increasing turbine vibrations. These conclusions were discussed with licensee management. A more expeditious resolution of the alarm masking problem by addressing the RFPT alarm may have enabled the operators to take action to prevent the scram.

d. Screen Wash System

The inspectors had identified in the previous inspection period a problem with the intake traveling screen wash system. During autumn, a large amount of leaves are often present in the Altamaha River. Traveling water screens are relied upon to prevent the leaves or other foreign material from being pulled into the Plant Hatch service water intake. The plant has two traveling screens which are each equipped with a spray nozzle wash system and rotating equipment. A flow trough is used to remove the debris washed off the screens. The inspector had found the screens, housings, and trough blocked with leaves. Additional review of this issue was made by the inspectors and the licensee. As a result of these reviews, the following discrepancies were noted: The PEOs were not adequately instructed as to how to perform a verification of spray nozzle function; each traveling screen structure has side doors that can be opened for a visual inspection; the PEOs had been looking through cracks in the traveling screen structure to verify wash water spray function.

The system may not have been operated correctly given the large amounts of material in the river. When in the automatic mode, the travel screen wash spray system operates based on a differential pressure across the screens. When the screens start to move, the differential pressure decreases rapidly and the screens move only a relative short distance, approximately 1/3 of a revolution. This dumps a large amount of debris into the flow trough and into the traveling screen structure, because when the screens stop the wash spray water also stops. Over a period of time the traveling screen structure and the flow trough become clogged with debris. The inadequate inspection of the screen structures and the short automatic operation resulted in the traveling screen structure and the flow trough becoming clogged with debris.

These items in combination rendered the travel screen wash system inoperable. It was incapable of adequately removing debris from the water being pulled in from the river. The screens were picking up leaves from the river, moving them through the clogged screen wash structure and dumping the excess leaves into the individual intake water bays. At the close of this report, operations management was reviewing the issue to determine the

appropriate corrective actions. Proper operation of this system is important to ensure that the service water systems do not become degraded. This item is identified as IFI 321/92-32-03: Intake Traveling Water Screen Issues.

No violation or deviations were identified.

3. Surveillance Testing (61726)

a. 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. 42SV-TET-005-2S: Integrated Leak Rate Test Preparation

2. 42SV-TET-003-2S: Primary Containment Integrated Leak Rate Test

3. 34SV-T49-002-2S: Primary Containment Hydrogen Recombiner System Function Test (Heatup to 600 F)

4. 42SV-R43-008-2S: EDG 2A LOSP/LOCA LSFT

5. 34GO-OPS-001-2S: (Attachment 8) Heatup and Pressurization Checks During Reactor Startup

6. 34SV-C41-001-1S: SBLC Recirculation Test

7. 34SV-C41-002-1S: SBLC Pump Operability Test.

The inspectors observed and reviewed many of the activities associated with the Unit 2 CILRT. This included independent periodic reviews of data during the test and reviews of data following the test. Other activities included in plant observations and reviews of preparations for the CILRT. The inspectors noted that during the pressurization, personnel were aware of the minimum and maximum pressurization requirements for the test, the pressurization source upon reaching test pressure was isolated from the containment and pressure - temperature

stabilization was observed prior to commencement of the leakage rate measurement. The inspectors observed the pretest briefing, attended discussions held during the test, and discussed the test status and data with test personnel. Pressurization commenced at 2:45 a.m. November 6, 1992, and was completed at 9:15 a.m. on the same date. The overall temperature was determined to be 87.16 F and the pressure was 72.33 psia. Stabilization was determined after 19 data sets at 1:45 p.m. with a temperature of 85.93 F, pressure at 72.06 psia and a dry air mass of 9,8215.08 lbm. The Type A Test total time leakage was completed after 33 data sets at 9:45 p.m. with a temperature of 86.3 F, pressure at 71.9 psia and a dry air mass of 9,7933.47 lbm. The test personnel performed a verification test which was completed at 3:00 a.m. November 7, 1992. The inspectors observed and reviewed the data collection, the calibration status of the instrumentation, and conduct of test personnel. The inspectors noted that although the resultant leakage was below the allowed leakrate, the leakage rate obtained over the past several ILRTs has been increasing and is approaching the allowable limit. The licensee is aware of this and is reviewing the issue. The inspectors concluded that the CILRT was conducted in accordance with approved procedures and by personnel familiar with the testing requirements.

b. Standby Liquid Control System Testing

During observation of the SBLC pump testing listed above, the inspector identified two discrepancies. The first issue involved the 1A SBLC pump testing performed to meet the requirements of Unit 1 TS 4.6.k and ASME section XI. As required by steps 7.2.23 to 7.2.27, the pump is run for two minutes (at the reference discharge pressure) and the change in the test tank level is used to calculate the flowrate of the pump. The inspectors have noted on previous tests that it is difficult for operators to obtain accurate data concerning the change in tank level. During this test, the initial data reported by the operator resulted in a flowrate well in excess of the reference flowrate multiplied by 1.1. Differences in sightglass level sighting and final tank level measurements were discussed. Small variations in tank level result in large flowrate errors. The inspector calculated that a one inch level error would result in a 2.5 gpm flowrate error. The entire acceptable range is about 7.5 gpm. The sightglass level also changes when the pump is secured. The inspector concluded that the current form of testing will not identify degradations in pump capacity unless a severe degradation occurs. While the test is sufficient to ensure that the SBLC pumps meet the TS required flowrate, the intent of section XI testing is also to identify degradation. The lack of accurate testing repeatability makes the detection of a slightly degraded flowrate difficult. The inspector noted that lubrication levels, outlet pressures, and vibration are also monitored and would likely indicate a degraded pump condition. The licensee indicated that the procedure will be enhanced in the near future.

The other discrepancy noted involved the direction of rotation of the 1A SBLC pump. The inspector identified that the rotation of the motor shaft did not match the arrow mounted on the coupling. Since the pump is a positive displacement pump, rotation direction does not effect pump capacity. However, correct rotation may be important to ensuring adequate lubrication of the pump internals. The inspector reviewed IN 91-27 which addressed an identical situation identified at another BWR in early 1990. The pumps involved were supplied by the same vendor and utilized in an identical manner to those at Hatch. The inspectors also reviewed Inspection Report 325,324/90-11 which contained additional details on the issue. Hatch maintenance personnel verified that the 1A pump was rotating in the incorrect direction and subsequently changed the electrical lead connections at the motor to correct the problem. The other three pumps were verified to be rotating in the correct direction. The licensee's investigation indicated that the last time the motor was de-terminated (and the error may have occurred) was in 1979.

The licensee reviewed the issue further and contacted the pump vender for additional information. The vendor representative stated that at the speed (370 rpm) that the pumps operate at, lubrication by way of a splash effect would sufficiently lubricate the pump for short term operation. The pump would properly operate for much greater a time than the 2 hour maximum period required to inject the boron if the system were required to shutdown the reactor. The oil and vibration analysis results for the four SBLC pumps indicate that the 1A pump is in the overall best material condition. The inspectors review of the pump technical manual did not identify any additional concerns. It was noted that the instructions for reassembly of the pump power frame specifically state that the crankshaft rotation should be checked as proper rotation is essential for lubrication of the power end components.

The inspector discussed the licensee's actions in regards to IN 91-27. Apparently the personnel who developed the internal response focused on the statements in the IN which indicated that visual rotation checks should be included with surveillance procedures and recommended such procedural changes be made. The operations and maintenance departments did not agree to revise the procedures to include the rotation checks and no further action was taken. The personnel responding to the IN had also obtained further information from the pump vendor which indicated that the reverse rotation was not a significant operability issue.

The inspectors concluded that the operability of the SBLC pump was not adversely impacted. While information obtained after the incorrect rotation was identified indicated that reverse rotation is not of large safety significance, the information provided in the IN was not properly utilized by the licensee. Identification and correction of conditions adverse to quality is required by

criterion XVI of Appendix B of 10 CFR 50. This NRC identified violation is not being cited because the criteria specified in section VII.B of the Enforcement Policy were satisfied. This is an isolated violation of minor safety significance and the licensee promptly initiated corrective actions. This issue is identified as NCV 321/92-32-01: Incorrect SBLC Pump Rotation.

One NCV was identified.

4. Maintenance Activities (62703)

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, cleanliness, and 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 2-92-1992: Set Mechanical Low Speed Stops for Recirculation Pump MG Set Scoop Tube Controller.

2. 42SP-092892-PZ-1-OS: Battery Jar Inspection

3. MWO 1-92-1743: RCIC Lube Oil Cooler

4. MWO 1-92-1744: Steam Supply Valve (1E51-F045) to RCIC Turbine

The inspector closely reviewed and monitored the performance of the above listed Unit 1 battery cell procedure. The procedures were developed to monitor the growth of cracks identified on the bottom of numerous battery cells. Over the last several months, the presence of small cracks has been identified in several Unit 1 station service battery cells. When cells were identified which were losing electrolyte, those cells have been jumpered out and subsequently replaced. The 1B battery appears to have the most problem cells. As discussed in SOR 1-92-116, the most recent example was cell 40. Cell 40 has been replaced and has been shipped offsite for failure analysis.

The inspectors have been reviewing the licensees actions on this issue as it developed. On September 25, 1992, SCS completed an initial safety assessment of the cracked station battery cell jars which concluded the batteries will be capable of performing their intended safety function. The assessment was based on a visual inspection of the batteries by licensee engineers and GNB (the battery vendor) representatives. Additionally, a test had been performed by Wylie laboratory on 3 cracked cells which had been replaced previously. Those cells, which had been

cracked such that a slow loss of electrolyte was occurring (small through wall cracks), survived a simulated seismic event. The assessment noted that measures should be taken to monitor both batteries to ensure no cells are leaking electrolyte. (As a cell has been identified as leaking, it has been jumped out and subsequently replaced). The inspectors verified that procedures contained appropriate requirements. (Operating Order 00-05-09925, issued September 30, 1992, requires a PEO to check the batteries for leaking electrolyte each day.)

The licensee is continuing to investigate the cause of the cracking. The inspector noted that the 1B battery has a significantly higher number of scratches on the cell bottoms than the 1A battery which could be indicative of improper handling during cell installation. The inspector also noted it is very difficult to distinguish cracks from scratches on the cell bottoms. Careful examination of the cell bottoms with an inspection mirror is required. The problems could be the result of some type of manufacturing deficiency in the cells.

The inspectors did not identify any weakness in the operability assessment of the batteries which concluded that the batteries are operable. One of the inspectors will be more closely examining this issue during a visit to the SNC offices during next inspection period. The inspectors will continue to monitor the licensees actions on this issue.

No violations or deviations were identified.

5. Controls on Overtime Hours (71707)

The inspectors examined the licensees control on overtime hours worked by personnel performing safety related activities. The requirements of Unit 1 TS 6.2.2.g and Unit 2 TS 6.2.2.g were reviewed as well as the requirements contained in procedure 30AC-OPS-003-0S: Plant Operations. Step 8.4.6 of procedure 30AC-OPS-003-0S requires that each department manager shall review overtime reports for all applicable Hatch personnel. These reports are submitted on a monthly basis for review by the AGM-PS or AGM-PO. The inspector reviewed these reports for October 1992, for the operations department and for the chemistry and health physics department. Twenty-two individuals of the operations department worked 25 hours in a 48 hour period which exceeded the guidelines by 1 hour. This was due to shifting to EST from DST on October 25 and was authorized in advance by the general manager in letter LR -GM-024-1092 dated October 22, 1992. No other instance of authorization for deviation from overtime limits were noted. The inspector also reviewed a sampling of operations personnel timesheets for three separate pay periods to ensure the correct values of overtime had been documented on the monthly overtime report. No discrepancies were noted. While significant effort is extended on monitoring and reporting of overtime hours, management emphasized that it is primarily a responsibility of each individual to not exceed overtime limits. The inspector noted that a "rolling 7 day period" was utilized to monitor hours as required by

the TS. The inspector noted that due to the Unit 2 refueling outage, a majority of the licensed operators had worked significant amounts of overtime. Several individuals approached the 72 hour/7 days limit very closely. The inspector discussed his observations with operation management. The inspector was shown an overtime data base computer tracking system that can be utilized by operations management to monitor percentage of overtime hours by individuals and groups. This system enables the managers to more closely follow specific individuals or groups to ensure limits are not exceeded.

The chemistry and health physics department overtime report listed an individual who had exceeded the 72 hours in 7 days TS limit without prior approval. An oversight by supervision personnel had resulted in the individual working nine twelve hours days in a row. The limit was exceeded by 36 hours. The discrepancy was identified by HP administrative personnel during compilation of the monthly overtime report. The inspector reviewed SOR 1-92-128 which addressed this problem. The involved supervisor was counseled. The overtime report also listed one other individual who had deviated from the overtime limits, but had not received prior approval to do so. This individual had worked 24.5 hours within a 48 hour period, exceeding the 24 hour limit by 30 minutes without prior authorization.

Both of these instances involved failures of HP supervisory personnel to properly control the overtime hours of plant HP personnel. While the second case involved a very short period of time, the first case involved an individual working nine 12 hour days without a day off. The inspectors noted that the individual involved should also have acted to prevent the problem. TS 6.2.2.g requires that deviation from the hourly guidelines must be authorized by specific members of management in accordance with the established procedures. Section 8.4 of 30AC-OPS-003-0S: Plant Operations, states that authorization may be obtained following the limitation if circumstances so dictate. The inspectors concluded that in these examples, conditions did not dictate later authorization of the deviation. This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in section VII.B of the Enforcement Policy. The licensee's internal monthly overtime report identified the violation. It is not of large safety significance and appears to be a problem which occurs infrequently based on this review. The corrective actions for this issue as stated in SOR 1-92-128 were prompt and considered appropriate by the inspectors. This issue is identified as NCV 321,366/92-32-02: Unauthorized Deviations of Overtime Limits by HP Personnel.

The inspectors had been informed that contract HP personnel had been working nominally 12.5 hours per shift instead of 12.0 hours. The reason provided for this was that a 30 minute meal break was taken during the shift and that time did not count as work time. The extra time was not turnover time which is excluded from the limits. The limits in TS 6.2.2.g are applicable to unit staff who perform safety related functions, including health physicists. This practice could

result in personnel being onsite more than 72 hours within a 7 day period without specific prior approval (for example if six days were worked in a row). The inspectors discussed this with senior HP management. It appeared that some levels of site HP management were not aware of this practice. The practice was immediately changed and contract HP personnel now work nominally 12 hour shifts (including meal time). The inspector noted that Hatch relies on contractors to limit their personnel overtime hours. The inspector met with supervisors from the two primary HP contractors utilized at Hatch and discussed overtime limits in detail. The inspector concluded that the supervisors within the contract organizations were aware of the limits and monitor personnel work hours with emphasis on the 72 hour limit. GPC HP supervisors prepare the work schedule and also monitor daily time cards. The inspector concluded that controls of overtime on HP contract personnel are adequate to ensure excessive overtime hours are not frequently exceeded without authorization. The practice of contract HP personnel nominally working shifts longer than 12 hours has been halted. The safety significance of the personnel working 12.5 hours shifts is not large. If turnover time is excluded (as permitted in the TS), the 72 hour limit would be exceeded by less than 3 hours and only if personnel worked 6 days in a row without time off. It also seems likely that safety related functions were not being performed in the 15-20 minutes worked in addition to turnover.

The inspector noted that during unit outage periods, the licensed operators on both units are worked on the same overtime schedule. During these checks the inspectors specifically identified that some personnel who were observed standing watch on Unit 1 (operating) had worked up to the 72 hour limit and numerous personnel had worked significant overtime hours. As stated in the TS, the objective is that operating personnel shall work a normal 40 hour week while the plant is operating. This could be interpreted to intend that personnel on the operating unit should work normally 40 hour weeks. The inspector discussed this issue with regional management. A similar issue had been raised at another Region II site and the inspectors also held discussions with that resident staff. Hatch TS requirements appear identical to that site. At that facility, it had been identified that personnel on an operating unit often worked excessive overtime when the other unit was in an outage. The inspectors noted that the 72 hour limit was apparently not as strictly enforced at that site as at Hatch. On March 25, 1992, a letter was issued from the director of NRR addressing the issue. The letter stated that the NRC staff will be reviewing the issue of shift scheduling and overtime hours as a generic item. Additionally, the NRC staff is currently reevaluating the current guidance for working hours when a unit is shutdown. The letter concluded that the site involved did not have to implement a compliance exception backfit (which required the overtime scheduling policy be revised) at that time. The inspector and regional management concluded that additional generic guidance should be issued by the NRC staff regarding shift operating hours during outages.

It was concluded that Hatch operating personnel strictly adhere to the work hour limits and deviations are rarely authorized. While in recent months problems involving inattention to detail and personnel error have occurred, no safety significant events have been specifically attributed to operator fatigue.

Despite the problems noted involving several GPC HP technicians, the HP contractor shift policy which was revised, and the significant overtime hours worked by numerous licensed operators during a unit shutdown, the inspectors concluded that licensee overall controls on overtime are consistent with the present interpretation of the regulatory requirements. The HP technician who worked significant hours in deviation of the limits involved an infrequent error by supervisory personnel. The HP contractor shift policy was of minimal safety significance. Licensed operators strictly adhered to the hourly overtime limits and met regulatory requirements. The inspectors noted that the licensee dedicates significant effort and management attention in monitoring the overtime hours worked by its employees.

One NCV was identified.

6. Inspection of Open Items (92700) (90712) (92701)

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

a. (Closed) LER 366/91-05: Personnel Error Results in Reactor Scram on APRM High Flux During Startup. This LER addressed a scram which occurred during a plant start-up. The reactor was at less than 1% rated thermal power and a heatup to rated temperature and pressure was in progress in accordance with procedure 34GO-OPS-001-2S: Plant Start-up. The reactor scrammed on APRM high flux at 12 % rated thermal power when feed water was rapidly injected into the reactor vessel in response to a decreasing water level due to the opening of a main steam bypass valve. The licensee determined that the bypass valve had opened because the pressure control set point for the valve was not maintained above reactor pressure as required by the startup procedure. Two personnel errors were identified. The first being that when the bypass valve opened the operators failed to recognize the opening of the valve. The second was a failure by the operators to maintain the bypass valve pressure setpoint above the actual reactor vessel pressure. Contributing to the rapid injection of water into the vessel was the failure of valve 2N21-F165, Feedwater Long Cycle Return to Condenser, which was actually closed but indicated in the control room as being open. The licensee's corrective actions included counseling the personnel involved and replacement of the positioner on valve 2N21-F165. Additionally, plant startup procedures were revised such that the positioning of the turbine bypass valves is controlled in a different manner. The revised method has resulted in better operator control of heatup rate and TBV positioning. The inspectors specifically noted that during

the most recent startup of Unit 2, the 2N21-F165 valve worked properly. Based on this review of the corrective actions, this LER is closed.

b. (Closed) LER 321/91-09: Design Deficiency could Affect Main Control Room Environmental Control System. This LER addressed a design issue which was identified by non-licensed personnel and involved the MCREC system not meeting the single failure design criterion as required by the FSAR. The personnel determined on July 21, 1991, that the three trains, A, B and C, of air conditioning compressors and air handling units did not meet single failure criterion due to the fact that the electrical power for the train C air conditioner compressor and air handling unit could be fed from either class 1E Division I Bus 1R24-S002 or from class 1E Division II Bus 1R24-S003. However, the controls for train C were dedicated from Division II only. The licensee's corrective action included the implementation of DCR 1H91-130 which provided an alternate power supply for the train C controls in the event that class 1E Division II power supply becomes inoperable. The inspectors reviewed the licensee's corrective actions, and based on this review, this LER is closed.

c. (Closed) LER 366/91-13: Spurious Electrical Spiking in Neutron Monitoring System Results in Reactor Protective System Actuation. This LER addresses an instance in which the RPS was actuated due to a trip signal from IRM 2C51-K601D. The unit was in a refueling outage with the vessel flooded and the core partially reloaded with fuel. With fuel loading in progress, the IRMs were operable and the shorting links in the RPS were removed in accordance with Technical Specifications. In this configuration a trip from any IRM would initiate a full scram. IRM 2C51-K601D initiated a full scram when spurious electrical spiking commenced. The operators noted that no other IRM or neutron monitoring system were spiking and therefore, bypassed the affected IRM. The spiking continued for approximately 15 minutes and stopped. The licensee was unable to determine the cause of the erratic behavior. No repair work was performed on the IRM and the operators returned it to service. The inspectors have not noted other significant problems involving IRM spiking. Based on this review, this LER is closed.

d. (Closed) LER 366/91-15: Component Failure Results in an Unplanned ESF Actuation. This LER addressed a Group 1 PCIS isolation which occurred when the four main turbines stop valves unexpectedly opened. The unit was in cold shutdown mode with preparations in progress for startup following a refueling cutage. The opening of the main turbine stop valves in conjunction with low condenser vacuum satisfied the PCIS Group I isolation logic. The opening of the valves occurred when the control input logic board for stop valve number 2 was pulled as part of the set-up and check-out of the EHC system. This along with a failed servo valve, 2N32-F009, caused the number 2 valve to open and the other stop valves to also open. (Their movement is controlled by the position of valve

number 2.) As part of the corrective action the failed servo valve was replaced. The valve was verified to be functioning and the individual servo valves on the four turbine control valves were verified as functional. During the recent startup after refueling the inspectors noted that the main turbine EHC valves performed properly. Based on this review, this LER is closed.

e. (Closed) VIO. 321/91-20-01: Inadequate Corrective Actions Involving MCREC System Design Deficiencies. This violation addressed the fact that the system did not meet single failure criteria requirements. This system was analyzed by the A/E in 1989 and did not identify the problem as also being a single failure issue. This analysis only indicated that a cable sizing concern existed. It was noted by the inspectors when the violation was written that the licensee had taken some immediate corrective actions to address the single failure. Inspection Report 321,366/91-20 contains additional details. The licensee responded to the violation, dated September 26, 1991, in which the immediate corrective actions were discussed. Additional corrective actions involved a change to procedure 34SO-Z41-001-1S, Control Room Ventilation System. A review of the procedure indicated that in order to preclude entering an LCO all three HVAC units would be operated in one of five options. These options specifically addressed the number of HVAC units in RUN, the alignment of the electrical supply to HVAC unit 1Z41-B003C, and which units could be in STANDBY or OFF. Based on this review of the corrective actions this item is closed.

f. (Closed) LER 321/91-21: Personnel Error Causes Unplanned ESF Actuation. This LER addressed a ESF action that occurred while electrical craft personnel were replacing existing fuses with properly documented safety - related fuses per MWO 1-91-4868, the Master Fuse List, and plant procedure 52CM-MEL-005-0S: Fuse Replacement. The procedure required the placement of a temporary jumper when replacing fuses in a circuit where continuity was required. A temporary jumper was being removed following replacement of a fuse in panel 1C71-P003D when it was inadvertently grounded. This caused a short circuit current which blew the other fuse in the panel. The resulting loss of power initiated the unplanned ESF. The cause was determined to be personnel error. The licensee's corrective action consisted of counseling the involved personnel. Based on this review, this LER is closed.

g. (Closed) DEV 50-321,366/91-23-01: Normal Operation of the MCREC system as described in the FSAR. This deviation addressed items involved in the operation of the MCREC which did not take into account the descriptions contained in the FSAR. The system should have been operated in accordance with the FSAR or the FSAR should have been changed to reflect the actual operation of the system. The licensee initially responded to the deviation dated December 3, 1991, and submitted a followup response, dated March 13, 1992.

In the response the licensee indicated that the plant procedure and the FSAR would be revised to reflect how the system was to be operated. As a result of the change the plant procedure, 34SO-Z41-001-1S, and the Unit 2 FSAR, section 6.4, Habitability System, both indicated that one or two trains of HVAC could be in service and that both exhaust fans would not normally be operated and their respective dampers would normally be closed. It was also noted that when only one train of HVAC was in service an additional train would be in standby to operate in case of a failure of the operating HVAC. Based on the review of these changes this item is closed.

h. (Closed) LER 366/91-16: Personnel Error Results in Missed Technical Specification Surveillance. This LER addressed a missed surveillance involving the PCIS. The unit was in cold shutdown with reactor coolant temperature at 170 degrees F when a plant engineer discovered that not all the required response time data was collected for the primary containment isolation function initiated from a high primary containment pressure signal. The specific equipment affected by the high PC pressure were the vacuum breaker isolation valves in the HPCI and RCIC systems and pressure sensor 2E11-N094D, (Drywell Pressure High). Reviews by the licensee indicated that this sensor's response time testing was omitted from procedure 57SV-MNT-012-2S, Response Time Testing of Pressure Sensor Channel B. Due to this omission the response time test for sensor 2E11-N094D was not performed during the 1989 Unit 2 outage. The inspector reviewed the latest revision of procedure 57SV-MNT-012-2S, effective date September 17, 1991, and noted the section 2.0, Applicability, subsection 2.1.11, listed sensor 2-E11-N094D, Drywell Pressure High. The inspectors also noted that in section 7, Procedure, steps 7.31.1 through 7.31.3.10 indicated the method for time response testing of sensor 22E11-N094D. Based on this review, this LER is closed.

i. (Closed) LER 366/91-20: Spurious Breaker Trip Results in ESF Actuation. The LER addressed an ESF actuation which occurred when protective breaker ZC71-52-30 on the output of the 2B motor generator set in the RPS power supply tripped on November 5, 1991. The protective breaker was designed to trip when under voltage, under frequency, over voltage or over current conditions exist. The breaker trip caused a loss of power to the B channels of the reactor protective, process radiation monitoring, neutron monitoring, primary containment isolation and offgas radiation monitoring systems. The loss of power in turn caused a half scram signal to the RPS, closure of various Group 1, 2 and 5 PCIS valves, and the MCREC System entered the pressurization mode. Part of the licensee's corrective action was to perform an engineering review to assess the suitability of the RPS protective breakers in their present application. The review was performed dated December 9, 1991, and designated as document B-GP-16905. The result indicated that the breakers installed in both units were suitable for the application as the RPS motor-

generator sets output breakers at HNP. The inspectors reviewed document B-GP-16905. Based on this review this LER is closed. Other LERs addressing spurious RPS power supply problems remain open.

j. (Closed) URI 50-366/91-21-01: Inadequate Corrective Action for IE Bulletin 80-06. This unresolved item addressed a design issue involving IE Bulletin 80-06. The licensee discovered that several SBGT system dampers did not fully meet the requirements of IEB 80-06. A major concern of the inspectors was the fact that the discrepancy was not identified earlier. The details as to this concern and the licensee's response were documented in Inspection Report 50-321,366/91-21 and 50-321,366/91-34. The licensee issued LER 321/91-14, dated December 17, 1991, which gave additional details. This LER was subsequently closed in Inspection Report 50-321,366/92-21. The portion of the unresolved item involving Unit 1 , URI 50-321/91-12-01, was closed in Inspection Report 50-321,366/91-34. The Unit 1 SBGT system, discrepancy was corrected when the licensee issued and implemented DCR 91-171. To correct the Unit 2 discrepancy the licensee issued and implemented DCR 92-012: Reactor Building Ventilation Isolation Components Reset Switch. The DCR installed a reset switch on the main control room panel. The inspectors verified the installation of a push button reset switch on control room panel HVAC 2H11-P657, labeled RX BLDG, ISOL DMPR RESET "A" 2T41-SR4. Based on this review, and the above listed previous reviews, this URI is closed.

k. (Closed) LER 321/91-27: Improper Sensing Line Installation Results in ESF Actuation. This LER addressed two events involving actuation of the automatic closure of the RWCU system isolation valves. Each event occurred when portions of the RWCU system were isolated and a partial system drain down occurred. The cause of these events was concluded to be the improper installation of the sensing lines for differential pressure transmitter 1G31-N012. The lines were initially installed without adequate slope and whenever a RWCU system partial drain down occurred, the sensing line also drained down giving a false high differential pressure. This in turn caused a group 5 isolation of the RWCU system. The licensee's corrective action was to walkdown each units sensing lines to verify the need for rerouting the sensing lines. The walkdown of the sensing line of both units have been completed. MWO 1-92-1774 has been issued to reroute the Unit 1 sensing lines during the next outage and AI number RC92-00014 has been issued to correct the Unit 2 sensing lines. Based on these actions this LER is closed.

7. Exit Interview

The inspection scope and findings were summarized on December 11, 1992, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings. 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
50-321/92-32-01	Opened and Closed	NCV - Incorrect Standby Liquid Control Pump Rotation, paragraph 3b.
50-321,366/92-32-02	Opened and Closed	NCV - Unauthorized Deviation of Overtime Limits by HP personnel, Paragraph 5.
50-321/92-32-03	Opened	IFI - Intake Traveling Water Screen Issues, paragraph 2b.

8. Acronyms and Abbreviations

AC - Alternating Current
A/E - Architect Engineer
AGM-PO- Assistant General Manager - Plant Operations
AGM-PS- Assistant General Manager - Plant Support
AHC - Access Hole Covers
AHU - Air Handling Unit
AI - Action Item
APRM - Average Power Range Monitor
ASME - American Society of Mechanical Engineers
ATWS - Anticipated Transient Without Scram
BWR - Boiling Water Reactor
BWROG- Boiling Water Reactors Owners Group
CFR - Code of Federal Regulations
CILRT- Containment Integrated Leakrate Test
CIV - Combined Intercept Valve
CR - Control Room
CRD - Control Rod Drive
CST - Condensate Storage Tank
DC - Deficiency Card
DCR - Design Change Request
DST - Daylight Savings Time
EBOP - Emergency Bearing Oil Pump
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
EHC - Electro Hydraulic Control System
ERT - Event Review Team
ESF - Engineered Safety Feature

EST - Eastern Standard Time
FPM - Fission Product Monitor
FSAR - Final Safety Analysis Report
FT&C - Functional Test and Calibration
GE - General Electric Company
GPM - Gallons per Minute
HP - Health Physics
HPCI - High Pressure Coolant Injection System
HVAC - Heating, Ventilation and Air Conditioning
I&C - Instrumentation and Controls
IFI - Inspector Followup Item
IN - Information Notice
IPE - Individual Plant Examination
IRM - Intermediate Range Monitor
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LOSP - Loss of Offsite Power
LPRM - Local Power Range Monitor
MCRECS- Main Control Room Environmental Control System
MFP - Main Feed Pump
MSIV - Main Steam Isolation Valve
MWE - Megawatts Electric
MWO - Maintenance Work Order
NCV - Non-cited Violation
NPRDS- Nuclear Plant Reliability Data System
NRC - Nuclear Regulatory Commission
NRR - Office of Nuclear Reactor Regulation
NSAC - Nuclear Safety and Compliance
PCB - Power Circuit Breaker
PCIS - Primary Containment Isolation System
PEO - Plant Equipment Operator
PM - Preventive Maintenance
PSIA - Pounds Per Square Inch Absolute
PSIG - Pounds Per Square Inch Gauge
PSW - Plant Service Water System
RCIC - Reactor Core Isolation Cooling System
RFP - Reactor Feed Pump
RFPT - Reactor Feed Pump Turbine
RHRSW- Residual Heat Removal Service Water System
RPS - Reactor Protection System
RPT - Recirculation Pump Trip
RTD - Resistance Temperature Detector
RTP - Rated Thermal Power
RWCU - Reactor Water Cleanup System
RWM - Rod Worth Minimizer
Rx - Reactor
SAER - Safety Audit and Engineering Review
SBGT - Standby Gas Treatment System
SBLC - Standby Liquid Control System
SCS - Southern Company Services
SER - Safety Evaluation Report

S/F - Single Failure
SIL - Service Information Letter
SNC - Southern Nuclear Company
SOR - Significant Occurrence Report
SOS - Superintendent of Shift (Operations)
SOV - Solenoid Operated Valve
SP - Suppression Pool
SPDS - Safety Parameter Display System
SRM - Source Range Monitor
SRV - Safety Relief Valve
STA - Shift Technical Advisor
TBV - Turbine Bypass Valve
TCV - Turbine Control Valve
TS - Technical Specifications
TSC - Technical Support Center
TSV - Turbine Stop Valve
URI - Unresolved Item