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

Report Nos.: 50-321/93-27 and 50-366/93-27

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 28, 1993 - January 01, 1994

Inspectors:	for Leonard D. Wert, Jr., Sr. Resident Inspector	1.13.94 Date Signed
	for Edward F. Christnot, Resident Inspector	1.13.94 Date Signed
	for Bob L. Holbrook, Resident Inspector	1.13.94 Date Signed
Approved by:	Pierce H. Skinner, Chief, Project Section 3B Division of Reactor Projects	1/19/94 Date Signed

SUMMARY

Scope: This routine resident inspection involved inspection onsite in the areas of operations including review of a Unit 1 scram, surveillance testing including testing of humidity sensors in the standby gas treatment system, maintenance activities, cold weather preparations, review of Information Notice 93-89, and review of open items. With the assistance of a regional inspector, detailed reviews of two previously identified unresolved items were performed.

Results: Three violations were identified:

The first violation addressed inadequate corrective actions regarding inaccurate Unit 2 reactor building stack flow rate indications. Significant disparity between two indication channels had been questioned by workers in 1990. In February 1993, an NRC inspector questioned the accuracy of the indications and noted several potential problems regarding the application of inaccurate flow rates. An unresolved item addressed the concerns. During additional review this report period, a regional inspector determined that some of the deficiencies had not been effectively addressed. The flow rate inaccuracies affected radioactive effluent release calculations. Incorrect stack flow rate values could have resulted in inaccurate accident offsite dose estimates

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(Violation 50-366/93-27-01: Inadequate Corrective Actions Regarding Inaccurate Reactor Building Stack Flow Rate Indications, paragraph 5).

The second violation addressed the failure to comply with Unit 1 Technical Specification requirements involving procedures. Following a Unit 1 scram on June 15, 1993, the operations manager directed that a step of procedure 34AB-C71-001-1S: Scram Procedure, not be performed. This step required that the Main Steam Isolation Valves be closed when reactor water level increased to +100 inches (Violation 50-321/93-27-02: Failure to Comply with Scram Recovery Procedure, paragraph 2d).

The third violation involved inadequate functional testing of the standby gas treatment relative humidity sensors. This condition has existed since their initial installation. Vendor information clearly stated that the relative humidity sensors should be tested on a periodic basis (Violation 50-321,366/93-27-03: Inadequate Testing of Standby Gas Treatment Humidity Sensors, paragraph 3b).

During this report period, a Unit 1 reactor scram occurred after a feedwater turbine tripped when a circuit breaker spuriously opened. Another reactor scram was narrowly averted when a condensate header isolation valve failed. In both instances, the inspector's review of the transients indicated that the control room operators had performed very well. The prompt actions of the operators prevented a reactor scram on low water level after the condensate valve failed (Paragraphs 2b and 2c).

During a review of the licensee's cold weather preparations, several minor discrepancies were noted. The inspectors concluded that overall, the licensee's actions were adequate to protect equipment during the mild winter conditions typically encountered at the site (Paragraph 6).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

G. Austin, System Engineer
D. Bennett, Chemistry Superintendent
S. Bethay, Hatch Licensing Manager, Southern Nuclear
*J. Betsill, Unit 2 Operations Superintendent
*K. Breitenbach, Engineering Support Supervisor
*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. Eason, Safety Audit and Engineering Review
*P. Fornel, Maintenance Manager
*O. Fraser, Safety Audit and Engineering Review Supervisor
G. Goode, Engineering Support Manager
*M. Googe, Outages and Planning Manager
D. Gosh, Senior Engineer, Southern Company Services
*J. Hammonds, Regulatory Compliance Supervisor
*J. Heidt, Manager-Hatch Project Nuclear Engineering and Licensing
*W. Kirkley, Health Physics and Chemistry Manager
C. Moore, Assistant General Manager - Operations
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
A. Wehrenber, Nuclear Support, Southern Company Services
*P. Wells, Operations Manager

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

NRC Resident Inspectors

*L. Wert
*E. Christnot
*B. Holbrook

NRC Region II Inspectors

G. Kuzo
D. Seymour

NRC management/officials on site during inspection period:

E. Merschoff, Director, Division of Reactor Projects, Region II
L. Plisco, Acting Director, Project Directorate II-3, NRR

*Attended exit interview

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

2. Plant Operations (71707) (92701) (93702)

a. Operations Status and Observations

Unit 1 operated at 100 percent RTP until an automatic scram occurred on December 7. The scram was initiated by the spurious opening of two 600 V AC breakers that deenergized two 600 V MCCs. This resulted in the loss of the auxiliary oil pump to the "A" RFPT. Subsequently the RFPT tripped on low oil pressure. The reactor water recirculation pumps failed to runback and a unit scram was automatically initiated on low reactor water level. The unit was returned to 100 percent RTP on December 9, 1993. This scram is discussed in Paragraph 2.b.

The operators performed a controlled shutdown of Unit 1 on December 24 following an automatic power reduction transient. The transient was initiated by a partial blocking of the condensate system at the condensate demineralizers isolation valve. The blockage occurred when the valve disk retaining pin detached, allowing the disk to rotate on the stem. This blockage resulted in a trip of a CBP and RFPT. A controlled shutdown was initiated to conduct maintenance repairs on the demineralizers isolation valve. The unit was restarted on December 28 and 100 percent RTP was achieved on December 29, 1993. This activity is discussed in paragraph 2.c.

Unit 2 operated at 85 percent RTP throughout the reporting period. Several control rods remain fully inserted to suppress neutron flux in the area of suspected fuel leak.

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.

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

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed. During a tour of the 158 foot elevation of the Unit 1

RB, one of the inspectors identified that two portable (on wheels) coolers were not secured. The coolers were in close proximity to the fission product monitoring system and other safety related piping. The coolers had been moved earlier in order to paint the floor where they had been stored. The inspectors informed the Unit 1 SS and prompt corrective action was initiated. Additionally, one of the inspectors noted that excess condensation from an overhead ventilation duct was dripping on the unsealed top of a Unit 1 remote shutdown panel. The panel was initially sealed with tape then covered with plastic. The excessive condensation was also reduced. No other significant deficiencies were noted.

b. Unit 1 Scram

At 6:02 a.m. EST on December 7, Unit 1 automatically scrammed from 100 percent RTP. The "A" RFPT tripped which resulted in a partial loss of feedwater to the reactor vessel. Reactor water level decreased from the normal +37 inches to -50 inches. The reactor scram occurred at +10 inches as expected. The top of active fuel is at -165 inches. Both reactor water recirculation pumps failed to runback as designed but tripped on low level as expected. PCIS actuated as expected. RCIC automatically started and injected into the vessel. HPCI automatically started up but did not inject water into the vessel because reactor level did not remain below the setpoint at which the injection valve (1E41-F006) was required to open.

The following events occurred and resulted in the reactor scram. Two breakers from 600V bus 1A spuriously opened and two 600V MCCs were deenergized. Deenergization of one of these MCCs (1F) initiated a chain of events that resulted in the reactor scram. MCC 1F provides power to the "B" auxiliary oil pumps for both RFPTs. The auxiliary oil pumps provides both lubricating and control oil pressure for the RFPTs. The "A" auxiliary oil pump for the "B" RFPT was in operation at the time of the scram and was not affected by the power loss. However, the "B" auxiliary oil pump was in operation for the "A" RFPT. When the loss of power occurred to the inservice auxiliary oil pump, the standby oil pump did not increase the oil pressure to above the pump trip setpoint of approximately 4 psig as designed. Subsequently the "A" RFPT tripped on low oil pressure. The RFPT trip resulted in the partial loss of feedwater.

Both reactor water recirculation pumps failed to runback to 44 percent speed as designed. The runback logic is initiated by sensing a discharge flow of less that 20 percent from either RFPT coincident with a reactor water level of less than or equal to +32 inches. This runback is designed to prevent a reactor scram on low level due to a loss of reactor feedwater condition.

The licensee initiated an ERT investigation to address the scram and equipment problems that occurred. Maintenance personnel performed lengthy investigations and conducted several different tests of the breakers and system loads from the MCCs. The cause of the two 600 volt breakers opening was not determined.

The investigators determined that the oil pressure switch that tripped the "A" RFPT actuated prior to the pressure switch that started the standby oil pump. This was due, in part, to the oil header pressure being maintained at 180 psig instead of 200 psig as expected. Also, the pressure switch that initiated the standby pump actuated at 163 psig instead of 195 psig as expected. The inspector's review of calibration data for the pressure switches (both RFPT) indicated that they were calibrated in June, 1990, and the setpoints were left within procedure tolerances. Apparently the pressure switches had drifted out of calibration. The licensee implemented design change 1-93-4753 which installed new pressure switches and isolation valves for both RFPT oil systems were installed. This allows testing and calibration of the switches while the RFPTs are in service. Additionally, all pressure switches for both RFPTs were calibrated and tested prior to unit restart.

The failure that prevented the reactor water recirculation pump runback was determined by the licensee to be a partial plugging of a flow transmitter. Each RFPT discharge header is equipped with a flow element and flow transmitter. The flow transmitters provide a signal (differential pressure) to the reactor water recirculation pump runback logic circuit on a loss of RFPT flow. During maintenance investigative activities, it was determined that flow transmitter FT-N21-N045, the discharge flow transmitter for the "A" RFPT, was partially blocked. It was theorized that the blockage allowed a delay in transmitting a loss of flow signal to the runback logic circuit. This would account for the failure to runback on loss of flow and would support the low reactor water level trip of the pumps. Past work history indicated that the sensing line coupling for the flow transmitter had been temporarily repaired in September, 1993. A small leak had been repaired using approved plant procedures. The temporary repair consisted of a weld repair on the leaking portion of the sensing line. The line was not breached during the temporary repair activities. However, it was theorized that the small leak allowed sediment and contaminates to collect in the sensing line to the point of partial blocking of the flow transmitter. Following this incident, the temporary repair was replaced with a new permanent weld repair. The licensee inspected, calibrated and performed a functional test for the flow transmitter. All sensing lines were flushed. Additionally, the pump discharge flow transmitter for the "B" RFPT was inspected and calibrated and all sensing lines were flushed. There were no problems noted concerning flow transmitter FT-N21-N047 for the "B" RFPT.

Following the repairs on flow transmitter FT-N21-N045, the licensee performed special purpose procedure 42SP-120793-PM-1-1S, Reactor Recirculation Runback Confirmation. The system responses were as expected and no deficiencies were noted.

The inspectors observed portions of the scram recovery actions in the CR. System operating procedures were being used and CR alarms were addressed as required. Operations management oversight as well as SRO supervision were evident. The inspectors discussed troubleshooting activities and strategies with plant management and the various craft personnel involved. Also, discussions were held with the ERT team leader and other members. On December 8, a conference call between the licensee, NRR and Region II NRC management was conducted to review plant conditions, equipment response, corrective actions and unit restart plans.

The inspectors independently reviewed the HPCI start logic and verified that the HPCI injection valve not opening was consistent for the plant conditions during the transient. A review of the SPDS tapes indicated that reactor water level had decreased to below the HPCI initiation setpoint and returned to above the initiation setpoint in a matter of seconds. Since the reactor water level only remained below the initiation setpoint for a matter of seconds the injection valve open logic was not satisfied. The HPCI system response was also discussed with the HPCI system engineer and confirmed to be correct.

The inspectors reviewed MWO 1-93-5990 and work packages associated with trouble shooting and testing of various systems. It was concluded the work and testing was thorough. The work record associated with the temporary repair of FT-N21-N045 did not indicate that the sensing line had been flushed. The inspectors concluded that not flushing the sensing line was reasonable since the process line was not breached. It was also determined that the normal calibration procedure would not have discovered that the sensing line was partially blocked. Also, the inspectors concluded that the operators response following the event was appropriate. The ERT conducted a thorough and detailed review and their recommendations were sound. Adequate testing was performed to support restart of the unit. The reactor was brought critical at 6:05 p.m. EST on December 9, and 100 percent RTP was achieved at 10:48 a.m. EST on December 11, 1993.

c. Unit 1 Shutdown

At 6:24 a.m. EST on December 24, while operating at 100 percent RTP, a CBP low suction pressure alarm actuated. Immediately thereafter the "A" CBP tripped and seconds later the "A" RFPT tripped. Operators observed that the condensate booster pump discharge pressure had decreased from the normal 400 psig to approximately 160 psig and that the "B" CBP had automatically started. During the process of manually decreasing reactor recirculating flow, an automatic runback occurred at +32 inches as expected. Reactor water level decreased from the normal level of

+36 inches to approximately +14.5 inches. A low reactor level half scram was received on the "A" RPS and was later reset by the CR operators. No additional engineered safety features actuations were received. As reactor recirculating flow was decreased, the region of potential instability was entered. Control rods were inserted, as required by procedures, to reduce power and load line to exit the region of potential instability. Reactor power was stabilized at approximately 58 percent RTP. Operators placed the "A" RFPT back in service to control level. The "A" RFPT subsequently tripped on low suction pressure. The "A" RFPT was again placed in service but was maintained at a lower speed.

An ERT was initiated to investigate the occurrence. Following the preliminary investigation, the ERT concluded that the most likely cause was an obstruction in the flow path downstream of the condensate demineralizers. Valve 1N21-F253, the condensate demineralizer's outlet isolation valve, was the primary suspect.

On December 25, the unit was brought to hot shutdown to allow maintenance activities on the suspected valve. The maintenance activities revealed that one of the retaining capscrews in the pin holding the valve disk to the stem had broken off. Inspection of the pin indicated that the capscrews were worn by long term vibration and that the disk had rotated on the stem. The broken pin as well as several other bolts were found in the CBP's suction strainer. Maintenance completed repairs on the valve. The pin was replaced and spot welded in place. The capscrews were replaced, locked tight and tie wired. A reactor startup was commenced and criticality was achieved at 2:25 a.m. EST on December 28. The unit was tied to the grid at 3:10 p.m. EST on December 28 and 100 percent RTP was achieved at 9:00 a.m. EST on December 29, 1993.

The inspectors reviewed the operating logs, held discussions with the CR operators, maintenance personnel and ERT members. A review of past work history for valve 1N21-F253 was also conducted. The inspectors concluded that the operating crew performed very well during the occurrence. The operators attention to detail, quick diagnosis of the situation and rapid response to system parameters and failures prevented a reactor scram. The decision to manually decrease reactor recirculation flow demonstrated good integrated system knowledge.

The inspectors review of work history on the valve indicated that MWO 1-91-824 was generated on February 2, 1991, for suspected seat leakage. The valve work was not performed due to unavailability of parts. The work was rescheduled for the upcoming refueling outage but was not performed apparently due to parts not being available during the available work window. The valve is a normally open valve which is operated very infrequently. If the maintenance had been performed on the valve as scheduled, this failure probably would have been prevented, however the inspectors concluded that it was not unreasonable for the licensee to postpone the work activities. Since no previous failures of such pins have occurred, it would not be expected that the licensee would foresee such a failure.

d. Unit 1 Main Steam Isolation Valves Open With High Reactor Water Level

On June 15, 1993, Unit 1 scrammed from 100 percent RTP. The scram was caused by false low reactor water level signals which resulted when a reactor level instrument system variable leg was depressurized. IR 50-321, 366/93-11, contains a detailed description of the event. During the review of the incident, the inspectors had concerns involving several issues. One issue involved actual reactor water level increasing to above the bottom of the main steam lines and the MSIVs were not shut as required by procedure 34AB-C71-001-1S: Scram Procedure. This issue was identified as URI 50-321/93-11-02, Main Steam Isolation Valves Open With High Reactor Water Level, pending additional review to assess the appropriateness and safety consequences of the actions. The reactor scram procedure requires that the MSIVs be shut when reactor water level exceeds 100 inches. During the recovery actions operators observed that reactor level had exceeded +100 inches and were making preparations to close the MSIVs. The operations manager directed that the MSIVs not be shut. At the time the decision to not shut the MSIVs, CR personnel had stopped all water inventory makeup to the vessel. The operations manager concluded that shutting the MSIVs under the existing conditions, given that the increase in level had been stopped, would insert additional complications into the recovery.

The licensee contacted General Electric to perform an evaluation of the scram and the main steam line flooding issue. The report indicated that the reactor water level increased to 126 inches above instrument zero and an estimated 20,000 gallons of water entered the main steam lines. The report concluded that there were no significant dynamic loading of the main steam lines during the scram event on June 15, 1993, which would result in safety concerns.

The inspectors reviewed the following documents in preparation for the resolution of the unresolved item.

General Electric report GENE-637-028-0993: Evaluation of Hatch Unit 1, 6/15/93 Scram.

Procedure 34AB-C71-001-1S: Scram Procedure.

Procedure 10AC-MGR-003-0S: Preparation and Control of Procedures.

Unit 1 Technical Specifications Section 6.8, Procedures.

The inspectors concluded that the safety significance resulting from the MSIV flooding was small. However, a safety related plant procedure was not followed and the established processes to change the procedure were not utilized. NRC regulations require that safety related procedures be complied with unless such actions would be detrimental to the health and safety of the public. The failure to comply with the procedure is identified as Violation 50-321/93-27-02: Failure to Comply with Scram Recovery Procedure.

One violation was identified.

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. 34GO-OPS-001-1S: Plant Startup (RWM Operability Check)
2. 34GO-OPS-065-1S: Control Rod Movement
3. 34SV-E51-001-2S: RCIC Valve Operability
4. 34SV-E51-002-2S: RCIC Pump Operability
5. 57SV-D11-016-2S: GE NUMAC MSL Radiation Monitor FT

The inspectors did not identify any significant problems during the observation of these surveillances.

b. Inadequate Testing of Standby Gas Treatment Humidity Sensors

Inadequate testing of the SBGT system humidity sensors had been identified by one of the inspectors on June 15, 1993, and is described in IR-50-321,366/93-11. This issue was unresolved pending the testing of the Unit 1 and Unit 2 RH sensors which control the A and B trains of the SBGT system heaters and subsequent determination of system operability. The heaters function to maintain RH below 70 percent. The issues to be resolved included RH sensor and SBGT train operability. Subsequent vendor evaluation indicated that the Unit 1 RH sensors were inoperable but that the Unit 2 RH sensors were operating as designed.

The licensee's actions regarding the identified URI, as detailed in a August 4, 1993 letter, were reviewed and discussed during a December 7, 1993 teleconference between selected NRC Regional and NRR representatives and cognizant licensee personnel.

Subsequent to December 8, 1993, a sample from the Unit 1 SBGT train B was collected and sent to a vendor testing laboratory. Based on the reported results of the charcoal testing (greater than 99.976 percent efficiency) the Unit 1 train B charcoal was determined to meet operational requirements. The charcoal testing was conducted in accordance with ASTM D3803-1989. On December 29, 1993, the inspector reviewed a vendor report specifying testing criteria, and the results achieved. Based upon the testing results and discussions with the licensee, URI 50-321, 366/93-11-03: Inadequate testing of Standby Gas Treatment System Humidity Sensors is closed.

The failure to periodically test the humidity sensors to ensure that the SBGT heaters would operate as described in the FSAR is considered a significant weakness. Vendor information clearly stated that the relative humidity sensors should be tested on a periodic basis. This issue is addressed as Violation 50-321,366/93-27-03: Inadequate Testing of Standby Gas Treatment Humidity Sensors.

One violation 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 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 1-93-5660 Replace Disconnecting Finger (stab) on Breaker Assembly - Normal Power Supply to 4160 V Bus 1A

2.	MWO 1-92-2773	Install Pressure Gage and Add Weights to EDG Fuel Transfer Oil Pump 1C2 for Vibration Purposes
3.	MWO 1-93-5417	HPCI System Flow Instrumentation Calibration Check
4.	MWO 2-93-3383	Replace Cell 89 in Unit 2 Station Service Battery 2B
5.	MWO 2-93-3385	Replace Cell 16 in Unit 2 Station Service Battery 2B

During observation of the EDG fuel oil transfer pump activities the inspector noted that operators used good communications including verbatim repeat backs and proper procedural equipment identification when lining up and starting the 1C2 pump.

For the HPCI activities the inspector noted that the pump discharge pressure during the testing had been increased from 1080 psig to 1100 psig. Discussions with the system engineer indicated that the 1080 psig had been used since initial system testing. A recent review by the engineer indicated that the pressure should be 1100 psig instead of the currently used 1080 psig. In order to prepare for the combined TS surveillance and ASME Section XI and Time Response Test, an engineering decision was made to check the calibration of the HPCI flow instrumentation. The inspector noted during the observation of the I&C work activities that the technicians used the approved method for tagging temporary lifted leads, used calibrated test equipment and used independent verification as required. The HPCI test were completed and the pump was placed in the alert range in accordance with ASME, Section XI requirements (IWP-3230, corrective action) due to vibration levels.

With the implementation of MWO's 2-93-3383 and 2-93-3385, the licensee completed the replacement of the five cracked cell jars located in the Unit 2 battery. IRs 50-321,366/93-17 and 93-20 contain additional information concerning this issue. The replacement of battery cell 89 was completed in an approved and controlled manner with the system engineer as an active participant in the evolution.

The inspectors did not identify any significant problems during observation of the maintenance activities.

No violations or deviations were identified.

5. Inaccurate Reactor Building Stack Flow Rate Indications

In IR 50-321,366/93-03 the inspectors documented several concerns regarding deficiencies in the Unit 2 RB stack flow rate indications. URI 50-321, 366/93-03-01: Failure to Identify Inaccurate RB Stack Flow Rate Recorder Indications, addressed the concerns. This issue was unresolved pending a determination of the significance of inaccuracies noted between the Unit 2 RB stack flow rate chart recorder (2T41-R621) "A" and "B" channels. Additionally, there were concerns regarding potential problems which could be caused by some applications of the flow rate indications. To evaluate the significance of the flow rate indication discrepancies, the inspectors reviewed licensee actions associated with the identified issue, compared flow rate recorder results with expected values based on design criteria, and evaluated the use of flow rate measurements or estimates during routine and emergency conditions.

In response to the questions asked by the inspectors and documented as an URI, licensee actions included specifying use of most conservative flow rate for dose assessment and development of a procedure to calibrate flow sensors against design flows of established fan lineup. The inspector verified that current procedures specified that the most conservative recorder channel flow rate value would be used for effluent release and/or dose assessment capabilities. In addition, the inspectors verified that the most conservative flow rate, 300,000 cfm, was used to establish effluent monitor setpoints and subsequently, the maximum recorder (1/2T41-R621) channel value was used to calculate the radionuclide effluent release data.

However, the inspector identified the following concern regarding accuracy of RB stack flow rate channel recordings from review of licensee procedural revisions initiated in response to the unresolved item. The licensee issued Surveillance Procedure 57SV-SUV-006-OS: Effluent Flow Rate FT&C, which provided instructions for positioning of the turbine rotor in the Unit 1 and Unit 2 RB stacks to compensate for turbulent flow areas. From review of the procedural acceptance criteria, the inspector noted that the Unit 1 and Unit 2 RB stack flow rates of approximately 229,000 - 263,000 and 143,000 cfm, respectively, as specified in Attachments 1 and 2 of the procedure, were in agreement with the normal design bases as detailed in a July 13, 1993 letter from Southern Company Services to Southern Nuclear Operating Company. Licensee records indicated that turbine rotor alignment for both RB stacks was conducted using the procedure during the validation on October 22, 1993. However, from review of the flow rate data, only the Unit 1 black pen channel was within the 5 percent acceptance criteria established by the procedure. The Unit 2 RB stack channels A and B results of 288,000 and 240,000 cfm were 2.01 and 1.67 times greater than the procedural acceptance criteria of 143,000 cfm ($\pm$5 percent) detailed in the surveillance procedure. The inspector noted that no comments or concerns were identified on the Validation Comment Resolution Sheet. In addition, additional discussions with licensee representatives indicated that no attempt to identify the concerns to supervisors for resolution of the issue had been initiated.

Subsequently, the inspector reviewed and discussed with cognizant licensee representatives current area ventilation inputs, and the exhaust fan lineup design capacity and the measured air flow rates for the Unit 1 and Unit 2 RB stacks. Licensee representatives indicated that between January and April, 1993, Control Building fans 1Z41-C008C and 2Z41-C008B were aligned to the turbine building turbine enclosure and feed pump areas to provide additional ventilation capacity. For the Unit 1 RB stack, without and with secondary containment isolation, maximum flow rates of 223,000 and 143,000 cfm, respectively, were calculated for the current fan alignment. For Unit 2, maximum flow rates of 192,000 and 153,000 cfm, without and with secondary containment isolation, respectively, were calculated. Based on the calculated flow rates the following concerns regarding RB stack airborne effluent releases and emergency preparedness capabilities were identified.

- The current methods for calculating RB stack effluent releases, radionuclide concentrations, and subsequent offsite dose assessments were reviewed and discussed with cognizant licensee representatives. No concerns were noted for determination of radionuclide concentrations in effluent. The inspector noted that TS Table 4.11.2-1(e) requires that the ratio of the sample flow rate to the sampled stream flow rate is to be known for the time period covered by each dose or dose rate calculation made. From review of selected November 1993 Stack Vent check sheets, the inspector noted that the Unit 2 RB stack flow rates averaged 250,000 cfm, that is approximately 31 percent above the expected flow rate. From discussions with cognizant licensee representatives and review of the most current Semiannual Effluent report, the inspector determined that errors in flow rate measurements were believed to be 10 percent or less as indicated in the report. The use of inaccurate Unit 2 RB stack ventilation flow rates to calculate the radionuclide inventory released as required to estimate the radiation hazards present is considered a deficiency.

- As a result of the concerns regarding the accuracy of the Unit 1 and Unit 2 RB ventilation stack flow rates, the inspector reviewed selected Emergency Preparedness procedures used to evaluate the offsite dose consequences associated with selected radiological emergency conditions. 10 CFR 50.47(b)(9) requires that adequate methods, systems, and equipment for assessing and monitoring actual or potential offsite consequences of a radiological emergency condition are in use. Licensee procedure 73EP-EIP-018-0S: Prompt Offsite Dose Assessment, September 1993 (Temporary Change 93-206) requires use of either SPDS output or the Unit 1 or Unit 2, Channel A or B flow rate readings to provide offsite dose estimates. From review of the SPDS parameter values as of December 8, 1993, the inspector determined that no changes had been made to the SPDS software parameters to include the flow rates from additional Control Building fans 1Z41-C00C and 2Z41-C008B added between January through April 1993 to ventilate selected turbine building areas through the Unit 1 and Unit 2 RB stacks. For the Unit 1 RB stack, without and with secondary containment isolation, maximum flow rates of 225,000 and 136,000 cfm, respectively, were used by the SPDS offsite dose calculation methodology. These values were within ± 10 percent of the estimated flow rates. However, for Unit 2, maximum flow rates of

225,000 and 105,000 cfm, without and with secondary containment isolation, respectively, were entered in the SPDS software. These values were approximately 117 and 69 percent of the expected flow rate values calculated for the Unit 2 RB stack. Additionally, for Unit 2 RB stack releases following a secondary containment isolation, offsite dose estimates would have been non-conservative. The failure to maintain accurate Unit 1 and Unit 2 RB stack effluent ventilation flow rates in the SPDS is considered a deficiency.

The primary concern in this issue is the licensee's failure to effectively address the identified inaccurate flow rate indications and the potential consequences. As early as 1990, personnel had formally questioned the wide disparity between the two channel indications. In IR 50-321,366/93-03, the inspectors described several concerns including effluent release monitoring accuracy and SPDS flow rate values. The failure to effectively identify and resolve the deficiencies is identified as Violation 50-366/93-27-01: Inadequate Corrective Actions Regarding Inaccurate Reactor Building Stack Flow Rate Indications.

One violation was identified.

6. Cold Weather Preparations (71714)

The inspectors reviewed and observed the licensee's activities involved with cold weather protection of plant equipment. The activities were primarily controlled by procedure 52PM-MEL-005-0S: Cold Weather Checks, and Operations Instruction DI-OPS-36-0989N: Cold Weather Checks. As part of the observation the inspector toured selected plant areas including the EDG building, fire pump building, intake structure, traveling screens area, condensate tanks, and the intake structure valve pit. The inspectors reviewed the procedures and the maintenance work order which implemented the PM (MWO 2-93-1980). The MWO was completed on September 9, 1993 and the PM procedure was signed completed September 7. The Operations Instruction directs personnel to tour areas of the plant to ensure that freeze protection is adequate whenever temperatures decrease to below 40 degrees F.

The inspectors also reviewed heat trace wiring diagrams H-14221 and H-40029 and vendor instruction manual SX 17519. The inspector noted that the heat trace system primarily consists of thermostats which are set to close electrical contacts at an ambient temperature of 40 degrees F and energize strip heaters. The drawings also indicated that when the individual heaters energize an amber light is activated indicating that voltage has been applied to the strip heaters.

Several items or minor deficiencies were noted by the inspectors:

- The sensing lines for a differential pressure instrument for the 1C EDG PSW supply piping located in the EDG building pipe chase were not insulated.

- The louvers for the 1C EDG room and the fire pump house did not appear to be fully functional. The motor driven 1C EDG louver was partially open when required to be closed. The four manually operated louvers in the fire pump house were not fully closed.

- The inspectors toured selected areas of the site during the early mourning hours on two occasions. The inspectors noted during one of these tours that the east door to the fire pump house was open. This building relies on space heaters for cold weather protection and with one of the doors open the protection was degraded.

- Deficiencies were noted involving the insulation and heat tracing on the Unit 2 CST level switches during a previous ESF walkdown (IR 50-321,366/93-11). The inspectors noted that the problems still existed. A DC had been written for the condition of one of the switches, but not the other.

- It was noted that the routine checks performed by the operators (even in cold weather conditions) did not require verification of heat trace indicating lights or closure of dampers, doors, and windows.

The inspectors discussed these deficiencies and observations with the licensee. The licensee is currently reviewing the items for corrective actions. The inspectors concluded that, given the typically mild winter conditions at Hatch, the licensee's cold weather protection program was adequate.

No violations or deviations were identified.

7. Information Notice 93-89: Potential Problems With BWR Level Instrumentation Backfill Modifications (92701)

The inspectors reviewed IN 93-89. This review indicated that if an specific drywell penetration isolation valve in the instrumentation reference leg were to be closed by an operator error, a significant erroneous indication of low reactor water level and high reactor pressure would result. The IN also discussed a potential issue involving a single failure vulnerability in the ECCS actuation logic. The inspectors had previously monitored the installation and testing of the Unit 2 Hatch and recorded observations in IR 50-321,366/93-26. The inspector reviewed the Hatch Unit 2 system installation in comparison to the IN and discussed this issue with licensee personnel in order to assess this vulnerability at Hatch.

The inspector determined that the installation of the Hatch backfill modification corresponded to the sketch referenced in the IN. However, at Hatch, if the reference leg penetration isolation valve were to be closed, only one of four instruments, which actuate the SRVs, would be affected. As discussed in IR 50-321,366/93-06, the implementation of DCR-91-135 installed an electronic pressure switch actuation system on the Unit 2 SRVs. This system modified the SRV actuation logic and as a result, reduced the potential consequences (at Hatch) if the valve was shut. It was noted that licensee personnel were aware of the contents of the IN and had issued a DC to document the review and actions taken.

The inspector concluded from the reviews, observations and discussions that the licensee was aware of the concern and has taken appropriate actions.

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) URI 50-321,366/93-03-01: Failure to Identify Inaccurate Reactor Building Stack Flow Rate Recorder Indications. This issue was unresolved pending a determination of the safety significance of the deficiencies. During this report period, this item was reviewed in detail by a regional inspector. Paragraph 6 of this report discusses the review of this item. Violation 50-366/93-27-01: Inadequate Corrective Actions Regarding Inaccurate Reactor Building Stack Flow Rate Indications was issued. This URI is closed.

b. (Closed) URI 50-321,366/93-11-03: Inadequate testing of Standby Gas Treatment System Humidity Sensors. This issue was unresolved pending testing of the Unit 1 and Unit 2 RH sensors which control the A and B trains of the SBGT system heaters. The results of the testing were necessary to assess the safety significance of the issue. This item was reviewed by a regional inspector. Paragraph 3b of this report discusses the review. Violation 50-321,366/93-27-02: Inadequate Testing of SBGT Humidity Sensors was issued. This URI is closed.

c. (Closed) URI 50-321/93-11-02: Main Steam Isolation Valves Open With High Reactor Water Level. This item was unresolved pending additional review to assess the appropriateness and safety consequences of the actions. Paragraph 2 of this report describes additional review which was performed this report period. Violation 321/93-27-02: Failure to Comply with Scram Recovery Procedure was issued. This item is closed.

d. (Closed) LER 50-366/93-01: Short Circuit Causes Trip of RPS Bus B and Unplanned ESF Actuation. This LER addressed an ESF actuation during the replacement of an LED in the MSIV logic. The activity was being performed by operations personnel. A loose wire to the LED grounded causing a momentary short circuit which the RPS logic detected as an undervoltage condition. The undervoltage protection relay actuated and the RPS MG set was tripped per design. As part of the corrective action the addition of a time delay to both units RPS undervoltage protection has been approved. Based on this review, the LER is closed.

e. (Closed) LER 50-321/93-03: Personnel Error Results in Missed EDG Surveillance. This LER address a missed TS surveillance test of the 1B EDG. A violation was issued in IR-50-321,366/93-08, and discussions of missed TS surveillance were documented in IRs-50-321,366/92-34 and IR-50-321,366/93-02. Based on the issuance of the violation and the fact that no missed surveillances have been identified over the last several months this LER is closed.

f. (Closed) LER 50-321/93-05: Blown Fuse Results in Unplanned ESF Actuation. This LER addressed an ESF actuations during the performance of surveillance procedure 57SV-D11-008-1S: Reactor Building Exhaust Vent Radiation Monitor Instrument FT. During the surveillance a blown fuse activated the B trains of the SBGT system and isolated the B train of secondary containment dampers and closed several Group 2 PCIS valves. The A train components had been temporarily jumpered out, in accordance with the procedure and did not actuate when the fuse blew. However, when the decision was made to exit the procedure and the A train jumper was removed, the A train components actuated. All work was stopped, reviews were conducted and it was recommended that Fuse 1D11-A-F14B be checked. The fuse was found to be blown. The reason for the blown fuse was not determined. A visual inspection for shorts, loose connections and frayed insulation was performed. All systems were restored. No problems were identified during this inspection. Based on this review of the licensee's activities, the LER is closed.

g. (Closed) LER 50-366/93-04: Group 2 PCIS Valve Closes During Procedure Performance. This LER addressed an occurrence, when during the performance of procedure 57SV-SUV-011-2S, ATTS Panel 2H11-P925 channel FT & C, the steam supply line isolation valve, 2E51-F008, for the RCIC system closed unexpectedly. I&C technicians were performing a functional test of the ATTS trip unit 2E51-N657A, which provides an isolation signal to RCIC valve 2E51-F008. A review of the procedure indicated that electrical links were to be lifted (step 7.4.6 of the procedure) to prevent a RCIC isolation logic signal. The inspector noted that two links, trip unit 2E51-N557A and trip unit 2E51-N660A, were required to be opened. The licensee stated that the valve closed when the I&C technicians increased the test signal to trip unit 2E51-N657A.

The inspector reviewed logic drawings H-27673 through 27680, RCIC system (2E51) Elementary Diagrams. It was noted on drawings H27675 and H27678 that steam line differential pressure (steam line break) was actuated by relay K12; relay K12 was actuated by parallel contacts, one-out-of-two logic, from the ATTS trip units 2E51-N657A and N660A; and link JJ-6 was in the electrical circuit for relay K12 and located in CR panel 2H11-P925. The inspector concluded from the independent observations and reviews that had link JJ-6 been lifted as required by the procedure, the valve would not have closed and the alarm would not have been actuated. The procedure was reperformed satisfactorily following the event and has been performed satisfactorily since. The licensee could not positively determine what caused the alarm and the valve closure. The inspector determined that the occurrence could not be duplicated when following the procedure. Based on the inspectors reviews and observations this LER is closed.

9. Exit Interview

The inspection scope and findings were summarized on January 6, 1993, 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
50-366/93-27-01	Open	VIO - Inadequate Corrective Actions Regarding Inaccurate Reactor Building Stack Flow Rate Indications, paragraph 5.
50-321/93-27-02	Open	VIO - Failure to comply with Scram Recovery Procedure, paragraph 2d.
50-321,366/93-27-03	Open	VIO - Inadequate Testing of Standby Gas Treatment Humidity Sensors, paragraph 3b

10. Acronyms and Abbreviations

AC - Alternating Current
AGM-PO - Assistant General Manager - Plant Operations
AGM-PS - Assistant General Manager - Plant Support
ASME - American Society of Mechanical Engineers
ASTM - American Society for Testing and Materials
ATTS - Analog Transmitter Trip System
BWR - Boiling Water Reactor
CBP - Condensate Booster Pump
cfm - Cubic Feet Per Minute
CFR - Code of Federal Regulations
CR - Control Room
CST - Condensate Storage Tank
DC - Deficiency Card
DCR - Design Change Request
ECCS - Emergency Core Cooling System
EDG - Emergency Diesel Generator
ERT - Event Review Team
ESF - Engineered Safety Feature
EST - Eastern Standard Time

F - Fahrenheit
FSAR - Final Safety Analysis Report
FT - Functional Test
FT&C - Functional Test and Calibration
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
LED - Light Emitting Diode
LER - Licensee Event Report
MCC - Motor Control Center
MG - Motor Generator
MSIV - Main Steam Isolation Valve
MSL - Main Steam Line
MWO - Maintenance Work Order
NRC - Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation
PCIS - Primary Containment Isolation System
P&ID - Piping and Instrumentation Drawing
PM - Preventive Maintenance
PRB - Plant Review Board
psig - Pounds Per Square Inch
PSW - Plant Service Water System
RB - Reactor Building
RCIC - Reactor Core Isolation Cooling System
RCS - Reactor Coolant System
RFP - Reactor Feed Pump
RFPT - Reactor Feed Pump Turbine
RG - Regulatory Guide
RH - Relative Humidity
RHR - Residual Heat Removal
RHRSW - Residual Heat Removal Service Water System
RPS - Reactor Protection System
RPV - Reactor Pressure Vessel
RTP - Rated Thermal Power
RWCU - Reactor Water Cleanup
RWL - Reactor Water Level
RWM - Rod Worth Minimizer
RX - Reactor
SAER - Safety Audit and Engineering Review
SBGT - Standby Gas Treatment
SOS - Superintendent of Shift (Operations)
SPDS - Safety Parameter Display System
SRO - Senior Reactor Operator
SS - Shift Supervisor
STA - Shift Technical Advisor
TS - Technical Specifications
URI - Unresolved Item
V - Volts