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February 28, 2000

Southern Nuclear Operating Company, Inc.
ATTN: Mr H. L. Sumner, Jr.
Vice President
P. O. Box 1295
Birmingham, AL 35201-1295

SUBJECT: NRC AUGMENTED INSPECTION TEAM REPORT 50-321/00-01 AND 50-366/00-01

Dear Mr. Sumner:

This inspection report documents the Nuclear Regulatory Commission's (NRC) review of a Unit 1 reactor scram and subsequent transient that occurred at Hatch Nuclear Plant on January 26, 2000. The reactor scram was initiated by a partial loss of main feedwater flow. Although several operational issues complicated the transient, the unit was safely shutdown and no safety limits were challenged. During and immediately after the event, some aspects of the operation of the main steam safety relief valves were not understood. The NRC chartered an Augmented Inspection Team (AIT) to evaluate the incident and the Southern Nuclear response. The AIT completed its onsite inspection on February 4, 2000. The enclosed report presents the results of this inspection.

The AIT conducted an independent inspection of the circumstances surrounding the events, monitored Southern Nuclear's investigations into the incident, and reviewed other related data and previous similar events. The AIT concluded that your staff's overall response to the transient was satisfactory.

We understand that you are considering additional improvements to address some operational performance issues noted during the event. Although no response to this report is required, we request that you contact us and schedule a meeting within 120 days from the date of this report to discuss your specific actions.

It is not the responsibility of an AIT to determine compliance with NRC rules and regulations or to recommend enforcement actions. These aspects will be reviewed in a subsequent inspection.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

Should you have any questions concerning this letter, please contact us.

Sincerely,

/R/

Luis A. Reyes
Regional Administrator

Docket Nos. 50-321 and 50-366
License Nos. DPR-57 and NPF-7

Enclosure:
NRC Augmented Team Inspection Report
50-321/00-01 and 50-366/00-01

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

AUGMENTED INSPECTION TEAM INSPECTION

Docket Nos:	50-321 and 50-366
License Nos:	DPR-57 and NPF-5
Report Nos:	50-321/00-01 and 50-366/00-01
Licensee:	Southern Nuclear Operating Company, Inc. (SNC)
Facility:	E. I. Hatch Plant, Units 1 and 2
Location:	P. O. Box 2010 Baxley, Georgia 31515
Dates:	January 26, 2000 - February 4, 2000

Team Leader: __________/R/__________________ __2/25/00___
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Approved by: _________/R/_________________ __2/25/00___
Loren R. Plisco, Director — Date Signed
Division of Reactor Projects

Enclosure

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EXECUTIVE SUMMARY

Hatch Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-321/00-01 and 50-366/00-01

The Augmented Inspection Team (AIT) reviewed Southern Nuclear (licensee) operations and engineering following a reactor scram (shutdown) on Hatch Unit 1 on January 26, 2000. A partial loss of feedwater occurred when a valve closed unexpectedly because of a problem with the valve control switch. This resulted in a reactor vessel water level decrease and an automatic reactor scram.

Two safety-related steam-driven injection systems automatically started and injected water into the reactor as designed. Reactor vessel water level was rapidly restored. At the lowest reactor vessel water level, there was still more than eight feet of water above the top of the reactor fuel. As the reactor water level increased, one of the injection systems, the High Pressure Coolant Injection system, did not automatically trip or turn off as designed. The operators closed isolation valves to prevent the water from flooding the main steam lines. Some water from the reactor vessel overflowed into the main steam lines.

Due to the water that entered both main steam lines and the safety relief valves (located on the steam lines), the operators did not receive the expected indications when they attempted to open several safety relief valves. After the switches for additional valves were operated, one safety relief valve provided the expected indications. Pressure was then controlled using several of the valves. Later, it was determined that all of the actuated safety relief valves had opened. The maximum value of reactor pressure was just slightly above normal operating pressure, and well below the setpoint for automatic actuation of the safety relief system.

Early in the recovery several attempts to restart the Reactor Core Isolation Cooling system, after it tripped on high reactor vessel water level, were unsuccessful. This turbine-driven pump tripped due to water in the steam supply to the turbine and the method that operators were using to restart it. Later in the recovery, the system was restarted. The licensee’s post-event review identified that the procedural guidance for restarting the Reactor Core Isolation Cooling system was not adequate for the existing conditions. That procedure was revised prior to restart of the unit.

Despite detailed investigation and testing, the licensee and the AIT could not determine why the High Pressure Coolant Injection system failed to trip immediately when the initial high reactor vessel water level condition occurred. Later in the recovery, the system tripped properly twice when reactor vessel high levels were reached. Testing of the system prior to restart confirmed that the high level trip operated.

The operators’ overall response to the reactor trip and resulting transient was sufficient to place the unit in a safe shutdown condition despite the equipment issues and unexpected indications. There were several operational issues which complicated the transient and recovery. The event occurred during shift turnover. A high number of personnel at the controls resulted in unclear lines of responsibility and communication difficulties during some phases of the event. The control board operators did not rigorously monitor and control reactor water level and injection systems during the recovery. There was a delay in shutting the main steam isolation valves and the operators did not identify that the High Pressure Coolant Injection system failed to immediately trip at the high level setpoint.

The licensee's reviews of operator performance were detailed and critical. In addition to corrective actions for the specific issues identified in this event, Southern Nuclear management is evaluating broader actions. These actions involve issues associated with shift turnover, operation of automatic controllers by control room operators during transient conditions, and other factors to enhance operator proficiency.

The licensee, with assistance from safety relief valve experts, completed detailed assessments of the effects of the water in the safety relief valves. The assessments concluded that the safety relief valves operated each time the switches were actuated in the control room. Testing and disassembly of several relief valves demonstrated that they were capable of performing their function and no unusual conditions were noted. Analyses were completed which supported that there was significant margin regarding overpressure protection of the reactor coolant system. The water in the main steam lines would not have prevented pressure mitigation if a high pressure condition occurred.

The potential effects of passing two-phase fluid or subcooled water through the safety relief valve internals, associated discharge lines, and the active components in the discharge lines were assessed. Reviews and inspections indicated that the components had not been exposed to stresses beyond analyzed values. Engineers conducted walkdowns of the safety relief valve discharge lines and other plant components that may have been subjected to the two-phase fluid flow. The evaluations fully supported continued operability of the safety relief valves and the related systems. The operability of instrumentation potentially affected by the water entering the main steam lines was verified. Affected transmitters were appropriately evaluated and replaced.

The valve control switch that initiated the unexpected reduction in feedwater flow was a General Electric Type CR 2940 switch. These switches were the subject of a 1977 Service Information Letter issued by General Electric which highlighted that the contacts of these switches could close prematurely on very slight movement of the switch. The AIT determined that the licensee's response to the Service Information Letter was not extensive. Additionally, the licensee did not initiate comprehensive corrective actions following a similar switch failure in 1996. Adequate corrective actions for the switches were implemented prior to the Unit 1 restart.

The AIT concluded that the event did not adversely affect the health and safety of the public. There was no radiological release associated with the event, and no operational safety limits were approached or exceeded.

The Southern Nuclear Event Review Team satisfactorily addressed the issues involved in the event. The licensee's investigation had observations and findings that were similar to those that the AIT reached in their parallel review. The AIT observed that some initial investigation efforts by the licensee were not rigorous, and this contributed to delays in understanding some details of the event. Important equipment and procedural issues were adequately reviewed and appropriate corrective actions were completed prior to plant startup.

<u>INSPECTION RESULTS</u>

Hatch Nuclear Plant, Units 1 & 2

Operations

- The licensee's post-event reviews of the Reactor Core Isolation Cooling (RCIC) system performance were acceptable. The system performed as designed during the event. The licensee addressed all the relevant areas, including comprehensive walkdowns of steam supply and exhaust piping to identify possible damage or abnormalities (Section O1.2).

- The licensee identified that the procedural guidance for restarting a tripped RCIC turbine was not adequate for the existing conditions. This contributed to several inadvertent overspeed trips of the RCIC turbine during the event. The system operating procedure was revised prior to restart of Unit 1 (Section O1.2).

- The licensee and the Augmented Inspection Team (AIT) were unable to conclusively determine why the High Pressure Coolant Injection System did not trip immediately when the initial high reactor water level condition occurred. Testing of the associated components did not identify the cause of the event but supported current operability of the system. The licensee's actions in response to this issue were appropriate (Section O1.3).

- The operators' overall response to the reactor trip and resulting transient was sufficient to place the unit in a safe shutdown condition despite some equipment problems and unexpected indications. The initiation of the transient at shift turnover and other factors complicated the event and recovery. The high number of personnel at the controls resulted in unclear lines of responsibility and communication difficulties during some phases of the event. The control board operators did not rigorously monitor and control reactor water level and injection system operations during the recovery. Although the control board operators acted reasonably regarding the SRV indications, the STA and other available personnel did not assist in diagnosis of the indications (Section O4.1).

- During the post-event analysis, the licensee's Event Review Team determined that the plant simulator did not properly model some aspects of Reactor Core Isolation Cooling operation. Simulator training indicated to the operators that the method used to restart a tripped Reactor Core Isolation Cooling turbine was appropriate and would be successful in actual plant operations (Section O5.1).

- The licensee's corrective actions regarding the feedwater valve control switch failure, prior to the restart of Unit 1, were adequate. The licensee's response to a 1977 Service Information Letter on this type of switch was not extensive. Additionally, the licensee did not initiate comprehensive corrective actions following a similar switch failure in 1996, despite the incident being entered into the corrective action program as a significant issue (Section O7.1).
- The Event Review Team's overall efforts satisfactorily addressed the issues involved in the event. The licensee's investigation had observations and findings that were similar to those reached in the AIT's parallel review. Early in the post-event review, some provisions of the licensee's post-event data collection procedure and Event Review

Team guidance document were not rigorously implemented. The corrective actions for the CR 2940 switches were not well-coordinated early in the investigation, but Operations management subsequently initiated more thorough actions. The licensee's post-event reviews of operator performance were detailed and critical. The AIT concluded that the important equipment issues were adequately reviewed and appropriate corrective actions were completed prior to plant startup (Section O7.2).

- There were several issues involved in this event which are important for the NRC and all Boiling Water Reactor licensees to fully understand. These issues warrant additional review to ensure a comprehensive understanding: (Section O8.1).

  - Effects on safety relief valve operation and indications when the valve is passing water instead of steam. Opening times may be slower, on the order of several seconds versus milliseconds, and blowdown of accumulated water may take several additional seconds. Discharge line pressure experienced when passing water may not be sufficient to actuate pressure switches used for position indication. Other safety relief valve indications, such as acoustics, may be affected as well.

  - The significance and potential effects of water entering the main steam lines. Procedural guidance for closing the main steam isolation valves and setpoints for the automatic high-level trips of the injection systems may not prevent complications due to water collecting in these lines.

Engineering

- Safety relief valve pilot assembly testing and inspection activities did not identify any problems with the pilot valve cartridges or the solenoid valves which would have prevented the associated safety relief valves from opening (Section E2.1).

- Analyses were conducted which concluded that there was significant margin regarding overpressure protection of the reactor coolant system for this scenario. The analyses fully supported that the water in the main steam lines would not have prevented pressure mitigation if a design basis accident occurred. No other licensing basis event scenarios were identified which would be more limiting than that analyzed in the licensee's evaluation (Section E2.2).

- The licensee appropriately assessed the potential effects of passing two-phase fluid or subcooled water on the safety relief valve internals, associated discharge lines, and the active components in the discharge lines. The reviews and inspections indicated that the components had not been exposed to stresses beyond analyzed values (Section E2.3).

- Actions to verify operability of instrumentation potentially affected by the water entering the main steam lines were comprehensive. Affected transmitters were appropriately evaluated and replaced (Section E2.4).

Report Details

Introduction and Charter

The NRC conducts Augmented Inspection Team (AIT) reviews of significant operational events at facilities licensed by the NRC. These events are those in which facts, conditions, and probable causes may contribute to better understanding of a safety issue or an important lesson that may be applicable to other nuclear plants. The NRC dispatched inspectors to the Hatch site and initiated a Special Team Inspection on January 26, 2000. After additional review, the NRC decided to conduct an AIT review because the reactor trip and subsequent transient involved possible important generic lessons and several complications that were initially difficult to understand.

The initial risk significance of this event was estimated and used as a factor in the decision to dispatch the Special Inspection Team. The major contributors to the increase in risk were the isolation from the normal heat sink (the main condenser) because of the closure of the main steam isolation valves, and the failure of the Reactor Core Isolation Cooling system to restart when demanded.

The objectives of this inspection were to:

1. Determine the facts of the specific event.
2. Assess the licensee's response to the event.
3. Assess the licensee's activities during event review and recovery.
4. Identify any generic aspects of equipment problems and operational issues.

Attachment 1 is the AIT charter. The AIT conducted a thorough inspection of the operational event. Team members analyzed information to determine the causes, conditions, and circumstances pertaining to the event. For example, the AIT independently reviewed computer data and control room chart recorder printouts. The team held discussions with many of the operators involved in the incident. One member of the AIT directly observed some of the recovery actions. The AIT also reviewed the licensee's analyses of specific equipment issues, including discussions with vendor representatives. The inspection emphasized fact finding and the determination of probable causes. The AIT directly examined plant equipment, observed investigative and maintenance activities, and discussed equipment operation with operators involved in the event.

I. Operations

O1 Conduct of Operations

O1.1 Description of Overall Event

The event was a reactor trip and operational transient which occurred on January 26, 2000. A partial loss of feedwater initiated the transient. A valve in the flowpath of feedwater to the reactor vessel closed unexpectedly. Later, it was determined that the valve closed because of a problem with the valve control switch. The valve closure caused a large reduction in feedwater flow, reactor water level decreased, and an automatic reactor trip occurred as expected. At the lowest reactor water level (-54 inches), there was over eight feet of water above the top of the reactor fuel.

The High Pressure Coolant Injection System and the Reactor Core Isolation Cooling System automatically actuated and injected water at large flowrates into the reactor as designed. These systems, along with the feedwater pumps, caused reactor water level to increase rapidly. The feedwater pumps and Reactor Core Isolation Cooling system tripped on high level as expected. The High Pressure Coolant Injection System did not immediately trip on high level and continued to inject water into the reactor for about one minute before it tripped. The Main Steam Isolation Valves (MSIVs) were then shut by the operators. This action is required by the Emergency Operating Procedures and is intended to prevent water from flooding the main steam lines. However, the reactor vessel water level was high enough so that some water entered the main steam lines.

At this point, pressure in the shutdown reactor began to slowly increase due to decay heat. In accordance with procedures, an operator attempted to open a safety relief valve to control reactor pressure. He did not receive the control panel indications he had been trained to expect for an open safety relief valve. Later, it was determined that this was due to the water that had entered the main steam lines and the safety relief valves. The operator then sequentially operated the control switches for additional valves, looking for the expected open indications. One valve provided the open indications that he was expecting and pressure was reduced. Several other safety relief valves were used successfully to control reactor pressure. Later, it was determined that each of the SRVs that the operator manipulated had opened. During the transient, reactor pressure reached a maximum value that was just slightly above normal operating pressure.

Reactor water level was controlled by the operators using the High Pressure Coolant Injection and Reactor Core Isolation Cooling systems. Several attempts to restart Reactor Core Isolation Cooling after it tripped on high level were unsuccessful. This turbine-driven pump tripped on overspeed several times. Water from the main steam lines had entered the line supplying steam to the turbine. The water affected the turbine control system. Procedural guidance and training was not adequate for restarting the tripped system under the existing conditions. The High Pressure Coolant Injection System was started several times for water level control and it properly tripped on high level twice during the recovery. Reactor Core Isolation Cooling was also restarted and operated for level control later in the recovery.

Subsequently, the operators opened the MSIVs and established the main condenser as a heat removal system. Early on January 27, the unit was placed in cold shutdown.

Attachment 2 of this report is a detailed sequence of events.

O1.2 Operation of the Reactor Core Isolation Cooling (RCIC) System

a. Inspection Scope (93800)

The AIT reviewed the performance and operation of the RCIC system during the event. AIT members observed the material condition of the RCIC system and related plant equipment, held discussions with plant personnel, and reviewed available RCIC performance data. The AIT evaluated the licensee's corrective actions and observed troubleshooting activities in order to assess the adequacy of the licensee's Event Review Team (ERT) review.

b. Observations and Findings

The RCIC system is designed to automatically initiate from a standby condition and inject water into the reactor vessel following a low reactor vessel water level signal. It is designed to continue operating without operator actions until a high reactor vessel water level occurs. At the high level setpoint, the steam supply valve automatically closes to isolate steam to the turbine. During operation, the turbine may receive other automatic trips by various conditions such as an electrical or mechanical overspeed condition. This results in rapid closure of the trip and throttle (T&T) valve. After closure, the T&T valve must be manually reset and reopened.

During the event, the RCIC turbine automatically initiated on low reactor vessel water level and continued to inject at rated flow until the steam supply valve closed on high reactor vessel water level as designed. After the high reactor vessel water level signal had cleared, an attempt to manually initiate RCIC operation was unsuccessful when the turbine tripped (T&T valve closed). Three additional attempts to restart RCIC were unsuccessful when the T&T valve again tripped closed each time. The RCIC turbine was subsequently successfully manually started and no further problems were identified with the operation of the RCIC system.

The ERT concluded that the initial closure of the RCIC T&T valve was due to an electrical overspeed trip which had resulted from water carryover into the turbine governor valve. The most probable cause was the presence of excessive moisture which resulted in flashing downstream of the governor valve and rapid turbine acceleration. These effects of excessive steam line moisture on RCIC operation had not been previously encountered at Hatch. This phenomena had been previously experienced at other nuclear facilities and was the subject of several NRC Information Notices (INs 85-50, 85-76, and 86-14). However, the primary concern addressed in those INs had been the accumulation of condensate in long horizontal runs of steam supply piping which are not present at Hatch.

The AIT verified from reactor vessel water level transient data that it was likely that water was present in the RCIC steam supply lines early in the transient. Additionally, based on discussions with a nonlicensed operator who was present in the RCIC room during the transient, the AIT determined that some water was drained from the RCIC steam supply piping following the first unsuccessful attempt to manually restart the RCIC turbine.

The three subsequent unsuccessful restart attempts of the RCIC turbine were attributed to the operator resetting and opening the T&T valve with the steam supply valve full open and the turbine control system demanding maximum speed. This operating practice resulted in rapid admission of steam into the turbine and the turbine tripped on electrical overspeed due to rapid turbine acceleration. Closure of the steam supply valve or reduction of the turbine governor demand signal prior to attempting to reopen the T&T valve would significantly reduce the transient on the turbine and avoid a possible overspeed trip of the RCIC turbine.

The licensee's ERT performed the following actions:

- interviewed operations personnel and compared their statements with available information and system performance data;

- evaluated the Safety Parameter Display System (SPDS) and RCIC Data Acquisition System information to verify that the RCIC T&T valve operated as expected;

- performed necessary maintenance inspection and applicable checks contained in the maintenance procedure on the T&T valve;

- walked down the steam supply and exhaust piping to identify possible damage or abnormalities; and

- evaluated RCIC and other systems for potential damage due to process and control instrumentation caused by the presence of water in steam supply lines.

The ERT identified a weakness in the RCIC system operating procedure. Procedure 34SO-E51-001-1S allowed the operator to attempt to restart the RCIC turbine by opening the T&T valve with the steam supply valve full open and the turbine control system demanding maximum speed. This methodology of restarting the tripped RCIC turbine contributed to repetitive overspeed trips of the RCIC turbine during the event. The AIT verified that the system operating procedure was revised to include new guidance on RCIC turbine recovery prior to restart of Unit 1. Section O5.1 of this report addresses additional training issues associated with restarting a tripped RCIC turbine.

The licensee's ERT, with the assistance of a consultant highly experienced in the details of RCIC operation, evaluated the system performance and determined that the RCIC system performed as expected during the event. Based on review of the licensee's preliminary reports, observation of diagnostic checks of the T&T valve, discussions with plant personnel, and examination of drawings and documents, the AIT determined that the ERT addressed all relevant areas for the RCIC system.

c. <u>Conclusions</u>

The licensee's post-event reviews of the RCIC system performance were acceptable. The system performed as designed during the event. The licensee addressed all the relevant areas, including comprehensive walkdowns of steam supply and exhaust piping to identify possible damage or abnormalities.

The licensee’s ERT identified that the procedural guidance for restarting a tripped RCIC turbine was not adequate for the existing conditions. This contributed to several inadvertent overspeed trips of the RCIC turbine during the event. The system operating procedure was revised prior to restart of Unit 1.

O1.3 High Pressure Coolant Injection (HPCI) System

a. Inspection Scope (93800)

The HPCI system did not immediately trip when the reactor vessel high water level setpoint was initially reached. The AIT observed investigative activities and reviewed maintenance work records and system operating data. The AIT discussed the event with licensee engineers, a consultant with HPCI system expertise, and licensed operators who were on shift during the event. Additionally, the AIT independently reviewed system control wiring diagrams, operating experience information, and procedures associated with the system.

b. Observations and Findings

The HPCI system initiated, as designed, at the reactor vessel low water level setpoint (-35 inches) and injected to assist the RCIC and Feedwater systems in recovering reactor water level. The system did not trip immediately when reactor vessel water level reached +51.5 inches as designed, but continued to operate for approximately 70 seconds before it tripped. The SPDS indicated reactor water level was +110.6 inches at the time of the trip. Subsequent to the initial operation, HPCI was manually restarted several times for reactor water level and pressure control. The system automatically tripped, as designed, on two occasions when the high reactor water level trip setpoint was reached.

The licensee’s review included extensive testing of equipment and review of records regarding the operation of the water level sensing transmitters, trip units, relays and connected wiring. Troubleshooting involved various activities including calibrations, voltage and resistance checks and cleanliness inspections of contacts and connections. The HPCI turbine stop valve performance was reviewed by comparing turbine stop valve operation from SPDS and computer data with overall expected system performance. In addition, control oil samples were analyzed for contaminants. The turbine stop valve solenoid coil was tested by verifying voltage and resistance indications were normal. No abnormalities were found as a result of the troubleshooting and testing. The ERT also developed a Fault Tree Analysis in the effort to determine the cause of the failure.

The AIT identified the electrical components associated with the high water level trip function and inspected them for dust or debris, loose connections, evidence of arcing, and wear. Operation of select components was observed during troubleshooting to verify no binding of the moving components. No problems were identified.

The licensee was unable to conclusively determine why the system failed to trip during its initial operation. The licensee was considering additional testing of the turbine trip system during routine future HPCI surveillance testing. The AIT concluded that the testing performed on the system was sufficient to verify proper operation.

c. Conclusions

The licensee and the AIT were unable to conclusively determine why the HPCI system did not trip immediately when the initial high reactor water level condition occurred. Testing of the associated components did not identify the cause of the event but supported current operability of the system. The AIT concluded that the licensee's actions in response to this issue were appropriate.

O4 Operator Knowledge and Performance

O4.1 Performance of Control Room Operators

a. Inspection Scope (93800, 93702, 40500)

One AIT member directly observed some of the control room operator actions in response to the transient. The AIT held discussions with several of the involved operators and observed portions of the licensee's reviews of operational performance. The AIT independently reviewed control room chart recorder printouts, operator written statements, and other performance data. The AIT assessed operational performance during the event and recovery.

b. Observations and Findings

Direct Observations of Response and Recovery

Upon entering the Unit 1 control room shortly after the trip, the inspector observed that there were about a dozen operators, supervisors, and support personnel in the control room. Specific observations included:

- Two operators (one an operations supervisor) were attempting to restart the RCIC system following initial trip on high reactor vessel water level. Other operators were starting the HPCI system in the alternate pressure control mode. The inspector observed, at times, as many as five operators at the control boards in the vicinity of the controls for RCIC, SRVs, and HPCI.
- The Emergency Operating Procedures (EOPs) were being actively used.
- Communications between operations supervisors and the control board operators were not formal and repeat-backs were not consistent.

The inspector determined from discussion with the unit Shift Supervisor that the unit was being maintained in the required pressure control band. The Assistant Plant General Manager-Operations, upon arriving in the control room, immediately questioned the large number of personnel in the room.

Overall Assessment of Operator Performance

There were several operational performance issues which complicated the transient and recovery:

- In response to the initial feedwater flow reduction, an operator took manual control of the master feedwater controller. This affected the controller response to the feedwater system transient and some subsequent operator actions.

- The increasing reactor water level was not properly monitored. Water level exceeded the 0 to +60 inches control band and was not reported as above the band until it had reached +95 inches. There was a delay in closure of the main steam isolation valves (MSIVs) as reactor water level increased. A note in the Emergency Operating Procedures requires that the MSIVs be shut if reactor vessel water level reaches +100 inches. The reactor water level was rapidly increasing. An operator, recognizing the water level was approaching this point, obtained concurrence from the Shift Supervisors (SS) before closing the MSIVs. The SS reported that he directed MSIV closure at about +102 inches and the valves were shut at an indicated level of +108 inches.

- The operators did not identify that the High Pressure Coolant Injection system failed to immediately trip when it initially reached the high reactor vessel water level setpoint. Data indicates that the system injected for approximately 70 seconds after level reached the trip setpoint.

- Several efforts to restart Reactor Core Isolation Cooling after the initial injection were unsuccessful because the procedural guidance and training for restarting a tripped RCIC turbine was not adequate. (see Section 01.2)

- The Shift Technical Advisor (STA) did not provide adequate technical support on the SRV indication issue to the operating crew during the incident or immediately after.

Several additional factors were noted by the AIT. The effects of these on the transient and recovery were not as clear as the above performance issues:

- The event occurred during the morning shift turnover. At Hatch, the senior reactor operators assume the shift prior to the formal oncoming shift briefing. In this case, the oncoming Superintendent of Shift and the individual Unit SS had assumed their duties. The offgoing reactor operators, who had been on shift for 12 hours (on the first night of the shift rotation) were at the controls for the initial event response.

- When the initial feedwater flow reduction occurred, briefing of the oncoming shift was ongoing in a room outside of the controls area but part of the main control room. There was not a SS in the immediate controls area. The oncoming Unit 1 SS immediately responded to the controls area.

- When the initial SRV switch operations did not result in the expected control panel indications (amber light from SRV discharge line pressure switch and reduction in pressure), the operators believed this indicated the SRVs did not actuate, and manipulated additional SRV switches. Operator training sessions had included discussions of the SRV discharge line temperature indications available on a back control room panel. Even after the initial response, the control room staff did not review the discharge line temperatures, which clearly indicated that the SRVs had operated.

All operational issues noted by the AIT during its parallel review of the event were addressed in the licensee's description of operator performance lessons learned and corrective actions. In addition to corrective actions for the specific issues identified in this event, Southern Nuclear management is evaluating broader actions. These would address issues associated with shift turnover, operation of automatic controllers during transient conditions, and other factors to enhance operator proficiency.

The AIT observed portions of the training of two crews in preparation for Unit 1 restart. The training addressed the significant issues noted above. The AIT observed that the operators were attentive and asked questions in order to understand some aspects of the training, particularly the SRV indications. Additionally, the AIT noted that the licensee promptly revised shift turnover practices in order to maintain a SS in the controls area of the control room during turnover.

c. Conclusions

The operators' overall response to the reactor trip and resulting transient was sufficient to place the unit in a safe shutdown condition despite some equipment problems and unexpected indications. The initiation of the transient at shift turnover and other factors complicated the event and recovery. The high number of personnel at the controls resulted in unclear lines of responsibility and communication difficulties during some phases of the event. The control board operators did not rigorously monitor and control reactor water level and injection system operations during the recovery. Although the control board operators acted reasonably regarding the SRV indications, the STA and other available personnel did not assist in diagnosis of the indications.

O5 Operator Training and Qualification

O5.1 Simulator Training for Reactor Core Isolation Cooling (RCIC) Operations (93800)

During the post-event analysis, the ERT determined that the plant simulator response associated with opening the RCIC trip and throttle valve with the RCIC steam supply valve, full open and the turbine control system demanding maximum speed was much slower than the actual plant response. The ERT determined that the simulator modeling of the RCIC system response with the above conditions utilized a linear response curve and resulted in the turbine tripping within 12 to 14 seconds. The actual plant response (non-linear) was for the turbine to trip in three seconds or less. Simulator training had indicated to the operators that the method used to restart a tripped RCIC turbine was appropriate and would be successful in actual plant operations. The AIT considered this issue to be a significant deficiency. The licensee documented this condition on plant simulator change request No. 20000114.

O7 Quality Assurance In Operations

O7.1 Investigation and Evaluation of Unexpected Feedwater Valve Closure

a. Inspection Scope (93800, 40500)

The AIT assessed the licensee's actions in identifying and investigating the cause of the sudden closure of the "B" 5th Stage Feedwater Heater Inlet Valve, which initiated the feedwater transient and subsequent low water level reactor trip. Additionally, the team assessed the licensee's immediate and long term corrective actions.

b. Observations and Findings

Following the event, the control room operators observed Unit 1 "A" and "B" feedwater temperatures diverging unexpectedly. An operator was dispatched to local control panel 1H11-P216 and discovered that valve 1N21-F005B, the 5th Stage Feedwater Heater Inlet, was indicating closed. The AIT observed that licensee personnel, as directed by the Event Review Team (ERT), took immediate actions to quarantine the control panel for detailed investigation. The ERT postulated that a possible cause of the valve closing was failure of the local panel control switch.

The licensee performed a detailed review, including numerous personnel interviews, to determine if any individual may have inadvertently contacted the switch near the time that the transient was initiated. The AIT noted that the corridor that the switch is located in is not particularly narrow and the switch does not protrude into the walkway. Nothing was found which provided additional information regarding whether the switch was physically contacted.

The control switch was identified as a General Electric (GE) Type CR2940. This type of switch was the subject of GE Service Information Letter (SIL) 217, issued in 1977, which highlighted that the contacts of these switches could close prematurely from very slight movement of the switch handle.

The AIT observed that the ERT took the following immediate actions based on a postulated switch failure:

- A maintenance work order was initiated to check contact resistance of the switch; maintenance electricians recorded changes in switch contact resistance when the switch was agitated.

- Maintenance and failure history for this type of switch was researched; a previous maintenance work order had been generated in 1996 to replace a Unit 1 switch that failed and caused a feedwater heater dump valve to close, inducing a slight feedwater heating transient.

- Maintenance and engineering personnel reviewed other mechanisms that could cause the valve to close unexpectedly, specifically electrical faults in the valve motor actuator main contactor. The AIT inspected the valve motor control center and found no discrepancies in the wiring or configuration of the main contactor.

An AIT member accompanied the ERT in a detailed as-found inspection of the switch. The switch was found to have a No. 1 cam as part of the switch operating mechanism. This cam is referring to a molded plastic component in the handle of the switch. Operation of the handle rotates the cam which controls movement of the plunger connected to the switch contacts. The inspector observed that the switch contact resistance could be changed from an infinite resistance value (contacts open) to some resistance between 30 and 200 ohms (contacts closed) with slight movement or tapping on the switch. The GE SIL had recommended replacing No. 1 cams with a molded, notched No. 2 cam. The notched cam engages the switch plunger mechanism more firmly.

Based on the inspection, the ERT and engineering staff conducted a systematic walkdown of all Unit 1 control panels to identify all switches with failure potential due to having No. 1 cams installed. The ERT identified approximately 120 switches, of which 60 were found in safety-related applications. All switches were prioritized for inspection and replacement with No. 2 cams. A total of 10 safety-related switches were found with No. 1 cams, and were immediately replaced. Additionally, the ERT developed a long term plan to identify, inspect and replace, if necessary, similar switches installed in Unit 2.

The AIT reviewed Significant Occurrence Report (SOR) CO9604446 documenting the 1996 switch failure and proposed corrective actions. The SOR recommended inspecting and replacing, if necessary, the applicable CR2940 switches on only the affected control panel.

The AIT reviewed the licensee's response to GE SIL 217 in 1981. The response stated that the switches would be replaced as necessary.

c. Conclusions

The licensee's corrective actions regarding the feedwater valve control switch failure, prior to the restart Unit 1, were adequate. The licensee's response to a 1977 Service Information Letter on this type of switch was not extensive. Additionally, the licensee did not initiate comprehensive corrective actions following a similar switch failure in 1996, despite the incident being entered into the corrective action program as a significant issue.

O7.2 Effectiveness of Southern Nuclear's Event Review Team Efforts and Investigation (40500)

The AIT concluded that the Event Review Team's overall efforts satisfactorily addressed the issues involved in the event. The AIT noted that the licensee's staff members, including the specific operators involved in the event, were critical in post-event reviews of operator actions. The licensee's investigation had observations and findings that were similar to those reached in the AIT's parallel review. The AIT observed that some initial investigation efforts were not rigorous. This contributed to delays in the understanding of some details of the event. Some provisions of the licensee's post-event data collection procedure and Event Review Team guidance document were not rigorously implemented. The corrective actions for the CR 2940 switches were not well-coordinated early in the investigation, but Operations management subsequently initiated more thorough actions. While the immediate post-event review process was not rigorous, subsequent review, including detailed simulator sessions with the operating crew, was thorough. The AIT concluded that the important equipment issues were adequately reviewed and appropriate corrective actions were completed prior to plant startup.

O8 Miscellaneous Operations Issues

O8.1 Potential Generic Implications

The AIT concluded that there were several issues involved in this event which are important for the NRC and all BWR licensees to fully understand.

The issues involving the introduction of water into the main steam lines and the discharge of the water through the SRVs may have implications to other facilities. Other BWRs have similar main steam line configurations, and the SRVs could be required to discharge collected water. The issues of assuring overpressure protection and adequate structural integrity for the water/two-phase discharge appear to be applicable to all BWRs.

The AIT determined that there were other potential generic issues regarding the initial lack of SRV position indication for the water/two-phase discharge condition. Other BWRs have differing indication instrumentation composed of pressure sensors, temperature sensors, and/or acoustic monitors. All of these devices require calibration to respond to the signal of interest, and the response for water/two-phase conditions is expected to differ significantly from the normal steam response.

The issues which warrant additional review to ensure a comprehensive understanding include:

- Effects on safety relief valve operation and indications when the valve is passing water instead of steam. Opening times may be slower, on the order of several seconds versus milliseconds, and blowdown of accumulated water may take several additional seconds. Discharge line pressure experienced when passing water may not be sufficient to actuate pressure switches used for position indication. Other safety relief valve indications, such as acoustics, may be affected as well.

- The significance and potential effects of water entering the main steam lines. Procedural guidance for closing the main steam isolation valves and setpoint for the automatic high-level trips of the injection systems may not prevent complications due to water collecting in these lines.

The AIT noted that there have been previous generic communications issued for similar incidents. In March 1987, there was an incident at Washington Public Power Supply System's WNP-2. Reactor vessel water level increased and entered the main steam lines. A safety relief valve was operated. In January 1988, there was a reactor vessel overfill incident at Nine Mile Point. Information Notice (IN) 88-77 and AIT Inspection Report 50-410/88-01 addressed the Nine Mile Point Unit 2 incident. Plant Hatch had reviewed these incidents and initiated actions in response to an Institute of Nuclear Power Operations report and the IN. Important issues in those events, including operation of safety relief valves with water in the main steam lines, were discussed in training presentations. Safety relief valve indication issues were not highlighted in these previous incidents.

II. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Testing and Inspection of Safety Relief Valve (SRV) Pilot Assemblies (93800)

The Hatch Unit 1 SRVs are the Target Rock two-stage design and are composed of a main stage and a small pilot stage. The valve either self-actuates due to system pressure at the mechanical setpoint or can be actuated by lifting the pilot with a pneumatic actuator in response to a manual or automatic electrical control signal to a solenoid valve in an air line to the pilot assembly. The SRVs are capacity certified for steam discharge according to the requirements of Section III of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code. The Code requires that SRVs have sufficient relieving capacity to limit system pressure to 1375 psig which is 110% of design pressure.

Initial indications during the event were that the SRVs had not functioned when called upon. An AIT member observed portions of the initial special testing of the SRVs after the unit reached cold shutdown conditions. Testing included checking pressure from the drain connector of each accumulator, checking for contaminants, and verifying voltage to the junction box in the drywall. The inspector observed portions of the first five SRV pilot valves being removed from the valve body.

On January 28, an NRC inspector observed testing of four SRV pilot valve cartridges and one SRV pneumatic operator solenoid valve at Wale Laboratories in Huntsville, Alabama. The components tested were from four of the SRVs initially believed to have not operated during the event. One pilot valve cartridge was disassembled by a Target Rock representative. The visual inspection did not detect any abnormalities which would have affected valve operation. One pilot valve cartridge was subjected to diagnostic testing which checked for proper operation of the pneumatic actuator. This test could also detect bonding between the pilot valve disc and seat, which is a known cause of setpoint drift problems with this type of valve. Proper operation of the pneumatic operator was displayed and no pilot valve disc-to-seat bonding was detected. This pilot valve cartridge as well as the remaining two were tested to determine the mechanical lift pressure setpoint. The setpoints were demonstrated to be within the Technical

Specification value of 1150 psig +/- 3%. The pneumatic operator solenoid valve which was tested demonstrated proper operation under various operating conditions.

The AIT concluded that the testing and inspection activities did not identify any problems with the pilot valve cartridges or the solenoid valve which would have prevented the associated SRVs from opening.

E2.2 Evaluation of Safety Relief Valve Performance with Water in Main Steam Lines

a. Inspection Scope (93800)

The AIT reviewed the licensee's analyses of the potential adverse effects of water in delaying or inhibiting the ability of the Safety Relief Valves (SRVs) to actuate and reduce pressure if called upon under design basis conditions. The AIT reviewed safety analysis and licensing basis information regarding the SRVs. The AIT discussed the analyses with licensee engineers and experienced consultants, including Target Rock and General Electric representatives.

b. Observations and Findings

Each SRV discharge line (often referred to as a tailpipe) is instrumented with temperature sensors primarily installed to detect SRV leakage and pressure sensors installed to detect SRV actuation. For normal steam conditions, the SRVs open in approximately .02 second, and the discharge line temperature and pressure sensors both indicate valve opening almost immediately.

Based on smearable samples taken from the SRVs during the post-event inspection activities and the isotopes present in the samples which would not have been present in a steam environment, the licensee determined that water filled at least up to the SRVs in the main steam lines. A better estimate of the quantity of water collected in each line is not known.

The AIT inquired about the possibility of the water in the SRV area inhibiting main stage opening even with pilot actuation. It was postulated that a failure of the stabilizer/balancing disk to seat could result in the main piston chamber not venting and the main stage not opening. However, a Target Rock representative provided additional information regarding the design of the stabilizer/balancing disk and stated it is spring loaded such that it will close even with no differential pressure across it (as the pilot is actuated). Additionally, water/two-phase test data for these valves and a similar pressurized water reactor pressurizer safety valve design, which also was tested for water/two-phase conditions, demonstrated that the main stages of the SRVs will open with water in the valves. The main stages will exhibit a slightly longer opening delay time than for steam conditions.

During the event, the control switches for numerous SRVs were manually actuated, one at a time, but some of the discharge line pressure sensors did not indicate SRV opening. The discharge line pressure sensors have a setpoint of 85 psig to actuate an indication on the control panel (amber light). The licensee and a GE representative determined that the pressure in the discharging water/two-phase flow at the location of the sensors was less than 85 psig.

Following the event, the licensee and the AIT examined the SRV discharge line and torus water temperature traces to verify that the SRV actually opened on demand. These traces were also reviewed by a Target Rock and a GE representative experienced with SRVs. It was determined that the discharge line temperatures clearly indicated that the valves actuated. Additionally, indications of temperatures in the torus near the SRV spargers indicated that four SRVs had opened.

Since the pressure sensing instrumentation in the SRV tailpipes did not immediately indicate the opening of the SRVs for the water/two-phase discharge, the AIT was interested in obtaining an estimate of the expected SRV opening time for these conditions. The GE representative indicated that there is no SRV total opening time test data for these specific fluid conditions. After review, the GE representative concluded that the opening delay time would be limited to approximately two to four seconds for the water conditions.

To address the effect of a large amount of water in the main steam lines on overpressure scenarios, the licensee performed an evaluation of the expected time to drain the water following SRV actuation. The evaluation assumed that no pressure reduction relief through the SRVs is available until the water is discharged from the main steam line having the largest volume of water. Along with other conservative assumptions, it assumed that only one valve opened to accomplish the draining. The evaluation concluded that with no pressure relief, decay heat could cause the pressure in the reactor vessel to rise from 1150 psig to 1325 psig in approximately eight minutes.

To determine the time necessary to drain the water between the SRV and the reactor vessel, the licensee performed several calculations. In the limiting case, the water is first converted to the same mass of steam which is then discharged. This drain time was estimated to be 75 seconds.

c. Conclusions

The AIT concluded that the analyses supported that there was significant margin regarding overpressure protection of the reactor coolant system for this scenario. Analyses fully supported that the water in the main steam lines would not have prevented pressure mitigation if a design basis accident occurred. No other licensing basis event scenarios were identified which would be more limiting than that analyzed in the licensee’s evaluation.

E2.3 Reviews of Structural Integrity of Main Steam Lines, Safety Relief Valves, and the Safety Relief Valve Discharge Lines Following Water Discharge

a. Inspection Scope (93800)

The AIT reviewed the licensee’s evaluations and inspections of the impact of passing two-phase fluid or subcooled water through the Safety Relief Valves on the valve internals, associated discharge lines, and the active components in the discharge lines.

b. Observations and Findings

Following the event, the licensee performed several activities to address potential structural integrity concerns as a result of excessive dynamic loading on components from the water/two-phase discharge. The licensee performed a walk-down of the main steam lines, the SRVs, and the SRV discharge lines to visually inspect for any unusual displacements of piping or supporting structures. The walkdown also included the RCIC and HPCI steam supply and exhaust lines. The licensee did not identify any damage.

General Electric also performed a structural analysis of the main steam lines, the SRVs, and the SRV discharge lines to support continued operation. The analysis involved the use of earlier evaluations by General Electric of similar postulated events for two other BWRs. These results were applied to the Hatch 1 event conditions by application of factors which account for differences in fluid inlet conditions and the valve actuation time. The results of the analysis indicate that American Society of Mechanical Engineers Service Level C stresses are met for the piping and the support loads are acceptable. The possible effects on the SRV discharge line vacuum breakers were also evaluated, and the loadings were determined to be acceptable. Based on this, GE concluded that these components are operable. GE considered this assessment to be qualitative in nature and recommended that a post-startup plant-specific analysis be performed to validate their findings.

The AIT reviewed documentation of walkdowns that were performed on the main steam lines from the reactor pressure vessel nozzles to the drywall penetrations and drywall portions of the SRV discharge lines to address potential damage to the piping. No problems were identified. In addition, the licensee performed a torque check of selected bolts on two SRV inlet flanges to check for possible bolt deformation which may have resulted from the dynamic thrust loads during an SRV discharge. The check was performed on the six bolts of the inlet flange that are located closest to the discharge flange for SRVs B and E, since these were expected to be the highest stressed bolts. The licensee found the torque on the SRV E bolts to be acceptable. On SRV B, two of the six bolts were found to be below the expected torque value. Since these two bolts were not the two closest to the discharge flange, the licensee determined that this condition was not evidence of a dynamic loading event. The licensee's vendor performed an assessment which addressed joint structural integrity and leak-tightness of the joint. Based upon the review of this information, the AIT concluded that no outstanding concerns existed.

c. Conclusions

The AIT concluded that the licensee had appropriately assessed the potential affects of passing two-phase fluid or subcooled water on the SRV internals, associated discharge lines, and the active components in the discharge lines. The reviews and inspections indicated that the components had not been exposed to stresses beyond analyzed values in the event.

E2.4 Instrument Operational Verification Activities

a. Inspection Scope (93800)

The AIT reviewed the licensee's actions to assess instrumentation connected to the main steam lines that may have been affected by the consequences of this event, specifically water intrusion, localized flashing, and water hammer. The AIT conducted independent inspections of instrumentation and reviewed instrumentation drawings.

b. Observations and Findings

After the incident, the licensee identified two Reactor Core Isolation Cooling (RCIC) steam line pressure transmitters, one RCIC steam line flow differential pressure transmitter, and one main steam line flow differential pressure transmitter that had been significantly affected. Two transmitters were damaged and the other two could not be adjusted back into calibration. Some of these transmitters were involved in a failure of the RCIC system to automatically isolate as the pressure in the reactor coolant system was reduced. This did not complicate the recovery. The licensee reported the failure in accordance with 10 CFR 50.72.

The AIT and the Southern Nuclear engineers, in analyzing the effect of steam line flooding on equipment and systems, postulated that localized flashing and/or water hammer may have induced pressure spikes that could have damaged instrument transmitters in the main steam lines, as well as the RCIC and High Pressure Coolant Injection (HPCI) system steam lines. The ERT initiated action to check the calibration of approximately 42 transmitters that may have been affected. The AIT inspected the two damaged pressure transmitters and observed that the bourdon tube-strain gage assembly connection was broken. These transmitters were replaced with identical Barton Model 763 transmitters, and the differential pressure transmitters were replaced with Rosemount devices.

The AIT reviewed the licensee's equivalency documentation, engineering evaluation and calibration data; no deficiencies were identified. The AIT also walked down accessible portions of transmitter piping and sensing lines. No damage was identified. The AIT reviewed instrumentation drawings to verify that the licensee had addressed all components connected to the main steam lines that may have been affected. The AIT determined that the licensee had implemented comprehensive actions to verify the calibration and operability of potentially affected instrument transmitters.

c. Conclusions

The licensee's actions to verify operability of instrumentation potentially affected by the water entering the main steam lines were comprehensive. Affected transmitters were appropriately evaluated and replaced.

III. Management Meetings and Other Areas

X1 Exit Meeting Summary

The AIT leader and the Region II, Director of Reactor Projects Division presented the inspection results to members of licensee management on February 4, 2000. The exit meeting was open to the public. Several representatives of public groups and news media were present. The licensee acknowledged the findings presented.

The inspectors were informed that some material examined during the inspection report was considered proprietary. All proprietary information will be returned to the licensee upon issuance of this report. No proprietary information is included in this report.

Partial list of persons contacted

Licensee

Betsill, J., Assistant General Manager - Operations
Crow, D., Licensing Manager
Fraser, O., Safety Audit and Engineering Review Supervisor
Googe, M., Performance Team Manager
Hammonds, J., Engineering Support Manager
Kirkley, W., Health Physics and Chemistry Manager
Lewis, J., Training and Emergency Preparedness Manager
Madison, D., Operations Manager
Moore, C., Assistant General Manager - Plant Support
Roberts, P., Outage and Planning Manager
Sumner, L., Vice President, Hatch
Tipps, S., Nuclear Safety and Compliance Manager
Wells, P., General Manager - Nuclear Plant

Inspection Procedures Used

37551: Onsite Engineering
40500: Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
93702: Prompt Onsite Response to Events at Operating Power Reactors
93800: Augmented Inspection Team

List of Acronyms

AIT	-	Augmented Inspection Team
BWR	-	Boiling Water Reactor
EOP	-	Emergency Operating Procedure
ERT	-	Event Review Team
GE	-	General Electric
HPCI	-	High Pressure Coolant Injection
IN	-	Information Notice
MSIV	-	Main Steam Isolation Valves
NRC	-	Nuclear Regulatory Commission
RCIC	-	Reactor Core Isolation Cooling
SOR	-	Significant Occurrence Report
SPDS	-	Safety Parameter Display System
SRV	-	Safety Relief Valve
SS	-	Shift Supervisors
STA	-	Shift Technical Advisor

T&T - Trip and Throttle

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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January 31, 2000

MEMORANDUM TO: Leonard D. Wert
Team Leader
Augmented Inspection Team

FROM: Luis A. Reyes //RA//
Regional Administrator

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER

An Augmented Inspection Team (AIT) has been established to inspect and assess the Hatch Unit 1 reactor trip and subsequent transient that occurred on January 26, 2000. The specific system failures and issues of concern are: (1) the loss of feedwater flow that initiated the transient; (2) the problems experienced when attempting to operate the pressure relief system; (3) the problems with restoring operation of the reactor core isolation cooling (RCIC) system following the high reactor vessel water level trip; (4) the failure of the high pressure coolant injection (HPCI) system to trip on high reactor vessel water level; and, (5) the cause and contributing factors for flooding of the main steam system.

The team composition is as follows:

Team Leader: L. Wert (RII)

Team Members: J. Munday (RII)
T. Fredette (RII)
J. Starefos (RII)
W. Bearden (RII)
G. Hammer (NRR)

The objectives of the inspection are to: (1) determine the facts surrounding the specific event; (2) assess the licensee response to the event; (3) assess licensee activity during their event review and recovery; and, (4) assess the generic aspects of the system failures and any operational issues.

For the period during which you are leading this inspection and documenting the results, you shall report directly to me. The guidance of NRC Inspection Procedure 93800, “Augmented Inspection Team,” and Management Directive 8.3, “NRC Incident Investigation Procedures,” apply to your inspection. If you have any questions regarding the objectives of the attached charter, contact me.

Attachment: AIT Charter

cc w/att: (See Page 2)

cc w/att: F. Miraglia, DEDR J. Munday, RII

Attachment 1

S. Collins, NRR
H. Berkow, NRR
T. Marsh, NRR
F. Congel, OEDO
M. Tschiltz, OEDO
C. Casto, RII
R. Wessman, NRR

AUGMENTED INSPECTION TEAM CHARTER
PLANT HATCH UNIT 1
FEEDWATER TRANSIENT AND REACTOR TRIP

Basis for the formation of the AIT - The reactor trip and subsequent transient at Hatch Unit 1 on January 26, 2000, appears to have the characteristics which meet the criteria of Management Directive 8.3, including: (1) multiple failures in safety-related systems; (2) possible adverse generic implications; and, (3) complications with probable causes unknown or difficult to understand.

Associated with the reactor trip of Hatch Unit 1 on January 26, 2000, the specific system failures of concern are: (1) the loss of feedwater flow that initiated the transient; (2) the problems experienced when attempting to operate the pressure relief system; (3) the failure of the high pressure coolant injection system to trip on high reactor vessel level; (4) the problems with restoring reactor core isolation cooling system operation following the high reactor vessel level trip; and, (5) the cause and contributing factors for flooding of the main steam system. Accordingly, the objectives of the inspection are to: (1) determine the facts surrounding the specific event; (2) assess the licensee response to the event; (3) assess licensee activity during their event review and recovery; and, (4) assess the generic aspects of the system failures. To accomplish these objectives, the following will be performed:

- Develop a sequence of events associated with the event of concern
- Assess the performance of plant systems during the event
- Assess the performance of licensed operators during the event
- Assess the licensee’s activities related to the event investigation (e.g., root cause analysis, extent of condition, precursor event review, etc.) and evaluate the effectiveness of the related event review team
- Assess the licensee’s activities related to event recovery (e.g., actions to restore system operability)
- Assess the potential impact of the partially flooded main steam system on the design basis operation of RCIC, HPCI, and pressure relief system
- Assess the potential generic aspects of the safety relief valve operation and the operation of RCIC and HPCI
- Document the inspection findings and conclusions in an inspection report within 30 days of the inspection
- Conduct a public exit meeting

Sequence of Events

Hatch Unit 1
Feedwater Transient and Reactor Scram
January 26, 2000

Initial Conditions

Unit 1 was on-line at 100% rated thermal power and 909 MWe. No significant equipment was out of service. The unit had been on line for 213 days. This data was compiled from several sources which are specified with the data times [Process Computer Alarm Printer (PCAP); Safety Parameter Display System (SPDS); Licensee Timeline dated January 29, 2000 (LIC); HPCI Data Acquisition System (HDAS); RCIC Data Acquisition System (RDAS); and the Control Room Log (LOG)].

Time January 26, 2000	Event
06:51:00 (PCAP)	Control Room operators receive alarms indicating feedwater control system trouble.
06:51:52 (LIC)	Feedwater Flow / Steam Flow mismatch indicated .
Exact Time Unknown	Operators take manual control of the feedwater controller and increased demand.
06:52:27 (SPDS)	Average reactor water level below control room alarm setpoint of 32".
06:53:11 (LIC)	Automatic reactor scram due to low water level (Setpoint 3").
06:53:12 (SPDS)	Manual reactor scram initiated
06:53:18 (LIC/SPDS)	High Pressure Coolant Injection (HPCI) system auto initiates due to low reactor water level. (level was -34.3")
06:53:18 (LIC)	Group 5 (Reactor Water Cleanup) primary containment isolation.
06:53:20 (LIC)	Group 2 (Hydrogen and Oxygen Analyzers, TIP, et al.) primary containment isolation.
06:53:23 (LIC)	Reactor Core Isolation Cooling (RCIC) system auto initiated (injection valve begins to open).
06:53:23 (SPDS)	Minimum average reactor vessel water level reached at -54.4"
06:53:25 (SPDS)	Mode switch to shutdown.
06:53:53 (SPDS)	Reactor Vessel Level reached +56".

06:53:55 (LIC)	Reactor feedwater pumps trip on high reactor water level.
06:54:08 (LIC)	RCIC tripped on high reactor water level (Operators did not recognize that HPCI did not immediately trip).
06:55:14 (LIC)	HPCI turbine stop valve is closed (HPCI tripped). Reactor water level indicates 110.6".
06:55:18 (SPDS)	Highest average reactor vessel water level at 110.8".
06:55:22 (SPDS)	Operators initiate Main Steam Isolation Valve (MSIV) closure to prevent water from flooding the steam lines.
06:55:38 (LIC/SPDS)	All inboard MSIVs closed. Main steam lines isolated. Reactor pressure is 755.3 psig. Pressure slowly increasing due to decay heat.
07:09:00 (SPDS)	Reactor water level 57.8" / Reactor pressure 1051.8 psig.
Approx. 07:09 (LIC)	Operators attempted to open safety relief valves (SRVs) to manually control reactor pressure; amber open indication fails to illuminate and expected rapid pressure reduction is not indicated.
07:10:12 (LIC)	Operators received positive light indication that SRV B opened when attempted. Opening SRV B armed one division of Low-Low-Set logic. Subsequently, pressure was controlled with SRVs A, B, G, and H.
07:10:13 (SPDS)	Average reactor pressure reached the maximum of 1085 psig.
07:16:43 (RDAS)	Operators attempt four times to restart RCIC for reactor water level control. The RCIC turbine apparently tripped via the electrical overspeed trip device. The overspeed trip was attributed to flashing of water into high energy steam downstream of the turbine governor valve and improper restart techniques.
07:18:20 (HDAS)	HPCI was manually started.
07:24:00 (SPDS)	Reactor water level 51.2".
07:24:22 (HDAS)	HPCI tripped, apparently from high reactor vessel water level.
07:40 (LOG)	Operators place 1B Residual Heat Removal (RHR) pump in service for suppression pool cooling.
07:41:06 (RDAS)	Operators successfully started RCIC for level control.

07:47 to 16:36	HPCI and RCIC systems were operated several times for pressure and level control.
10:05 (LOG)	Operators re-opened MSIVs and established the main condenser as the primary heat sink.
<u>January 27, 2000</u> 00:48 (LOG)	1A RHR loop placed in shutdown cooling mode.
02:45	Unit 1 in Mode 4, Cold Shutdown.