Georgia Power Company
40 Inverness Center Parkway
Post Office Box 1295
Birmingham, Alabama 35201
Telephone 205 877-7279

Georgia Power
the southern electric system

J. T. Beckham, Jr.
Vice President—Nuclear
Hatch Project

HL-1522
001330

March 14, 1991

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

PLANT HATCH - UNIT 1
NRC DOCKET 50-321
OPERATING LICENSES DPR-57
LICENSEE EVENT REPORT
COMPONENT FAILURE CAUSES
TURBINE TRIP AND REACTOR SCRAM

Gentlemen:

In accordance with the requirements of 10 CFR 50.73(a)(2)(i) and (iv), Georgia Power Company is submitting the enclosed Licensee Event Report (LER) concerning a condition that was prohibited by the plant Technical Specifications and the unanticipated actuation of some Engineered Safety Features (ESFs). This event occurred at Plant Hatch - Unit 1.

Sincerely,

J. T. Beckham, Jr.

JJP/ct

Enclosure: LER 50-321/1991-004

c: (See next page.)

IE22
/1

Georgia Power

Enclosure:

c: <u>Georgia Power Company</u>
Mr. H. L. Sumner, General Manager - Nuclear Plant
Mr. J. D. Heidt, Manager Engineering and Licensing - Hatch
NORMS

<u>U.S. Nuclear Regulatory Commission, Washington, D.C.</u>
Mr. K. Jabbour, Licensing Project Manager - Hatch

<u>U.S. Nuclear Regulatory Commission, Region II</u>
Mr. S. D. Ebneter, Regional Administrator
Mr. L. D. Wert, Senior Resident Inspector - Hatch

001330

NRC Form 366 (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92

LICENSEE EVENT REPORT (LER)

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TITLE (4)
COMPONENT FAILURE CAUSES TURBINE TRIP AND REACTOR SCRAM

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQ NUM	REV	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										05000
02	12	91	91	004	00	03	14	91		05000

OPERATING MODE (9): 1

POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR (11)

[ ] 20.402(b)	[ ] 20.405(c)	[X] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[ ] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[ ] OTHER (Specify in Abstract below)
[ ] 20.405(a)(1)(iii)	[X] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
[ ] 20.405(a)(1)(iv)	[ ] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
STEVEN B. TIPPS, MANAGER NUCLEAR SAFETY AND COMPLIANCE, HATCH	912	367-7851

COMPLETE ONE LINE FOR EACH FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORT TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORT TO NPRDS
B	JE	RV	T020	YES		X	TG	PS	B069	NO

SUPPLEMENTAL REPORT EXPECTED (14)

[ ] YES (If yes, complete EXPECTED SUBMISSION DATE) [X] NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

ABSTRACT (16)

On 2/12/91 at approximately 0911 CST, Unit 1 was in the Run mode at an approximate power level of 2436 CMWT (approximately 100% rated thermal power). At that time, the unit scrammed on Turbine Stop Valve (TSV) closure. The main turbine tripped on a low Electrohydraulic Control (EHC) system hydraulic fluid pressure signal. Reactor water level decreased to approximately 3 inches above instrument zero and was restored to normal using the Reactor Feedwater Pumps (RFPs). Reactor vessel steam dome pressure briefly peaked at approximately 1111 psig and the Bypass Valves (BPVs) successfully controlled pressure. No Safety Relief Valves (SRVs) lifted. The pressure experienced in the main steam lines was transitory and apparently less than reactor vessel steam dome pressure. However, using steam dome pressure, the SRVs were possibly not in compliance with their 1% Technical Specifications tolerance requirement. The valves were removed and tested in accordance with code requirements. The actual drift experienced was within the bounds of a previous analysis demonstrating adequate overpressure protection.

The cause of this scram was vibration-induced component failure of Hydraulic Fluid Pressure Switch 1N32-N300. The cause of the SRV setpoint drift was corrosion-induced bonding of the surface between the pilot valve disc and seat.

Corrective actions for this event included replacing the pressure switch and moving it away from the source of vibration. The SRVs were tested and refurbished. Georgia Power Company (GPC) will continue to participate in the BWR Owners' Group action plan to resolve setpoint drift.

TEXT

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor
Energy Industry Identification System codes are identified in the text as (EIIS Code XX).

SUMMARY OF EVENT

I. SCRAM DUE TO COMPONENT FAILURE

On 2/12/91 at approximately 0911 CST, Unit 1 was in the Run mode at an approximate power level of 2436 CMWT (approximately 100% rated thermal power). At that time, the unit scrammed on Turbine Stop Valve (TSV, EIIS Code TA) closure. The main turbine tripped on a low Electrohydraulic Control (EHC, EIIS Code TG) system hydraulic fluid pressure signal. Reactor water level decreased to approximately 3 inches above instrument zero and was restored to normal using the Reactor Feedwater Pumps (RFPs, EIIS Code SJ). Reactor vessel steam dome pressure briefly peaked at approximately 1111 psig and the Bypass Valves (BPVs, EIIS Code SO) successfully controlled pressure.

The cause of the scram was vibration-induced component failure of Hydraulic Fluid Pressure Switch 1N32-N300.

Corrective actions included replacing the pressure switch and moving it away from the source of vibration.

II. SAFETY RELIEF VALVE (SRV) SETPOINT DRIFT

During the pressure transient following the scram, no Safety Relief Valves (SRVs, EIIS Code RV) lifted. The pressure experienced in the main steam lines was transitory and apparently less than reactor vessel steam dome pressure. However, using steam dome pressure, the SRVs were possibly not in compliance with their 1% Technical Specifications tolerance requirement. The valves were removed and tested in accordance with code requirements. The actual drift experienced was within the bounds of a previous analysis demonstrating adequate overpressure protection.

The cause of the SRV setpoint drift was corrosion-induced bonding of the surface between the pilot valve disc and seat.

Corrective actions included the testing and refurbishing of the SRVs. Georgia Power Company will continue to participate in the BWR Owners' Group action plan to resolve setpoint drift.

TEXT

DESCRIPTION OF EVENT

I. SCRAM DUE TO COMPONENT FAILURE

On 2/12/91 at approximately 0902 CST, Unit 1 was in the Run mode at an approximate power level of 2436 CMWT (approximately 100% rated thermal power). At that time, plant Maintenance and Operations personnel, with the assistance of a General Electric representative, were troubleshooting reported problems, specifically large swings in discharge pressure with the "B" EHC system hydraulic fluid pump. With the "A" EHC pump in service, the "B" EHC pump was started per procedure 34SO-N32-001-1S, "EHC Hydraulic System." Maintenance and General Electric personnel reported seeing slight (less than 100 psig) pressure swings when the "B" EHC pump was started. A minor adjustment to the pump eliminated the pressure swings. Personnel then ran both the "A" and "B" EHC pumps in parallel for approximately 5 minutes to ensure the "B" EHC pump was running smoothly and steadily.

At approximately 0909 CST, the "A" EHC pump was removed from service per procedure 34SO-N32-001-1S. Personnel at the pump and in the Main Control Room reported the indicated EHC system hydraulic fluid pressure was approximately 1600 psig. This was the same pressure indicated with both pumps running. Personnel at the pump also reported the "B" EHC pump appeared to be running normally, with an indicated discharge pressure of approximately 1600 psig.

At approximately 0911 CST, Operations personnel in the Main Control Room reported seeing alarm lights flickering on the lower portion of alarm panel 1H11-P650. Approximately 1 second later, the main turbine tripped, causing a Reactor Protection System (RPS, EIIS Code JC) actuation and a scram on TSV closure. A check of the main turbine supervisory panel showed the main turbine trip resulted from a low EHC system hydraulic fluid pressure signal.

As expected, reactor water level decreased due to void collapse. As the water level decreased from its normal level of 35 inches above instrument zero to about 12 inches above instrument zero, a second RPS actuation on low reactor water level was received per design. This occurred approximately 4 seconds after the initial scram. Also received was a Group 2 Primary Containment Isolation System (PCIS, EIIS Code JM) isolation signal on low reactor water level. The Group 2 Primary Containment Isolation Valves (PCIVs) closed per design.

Water level decreased to its lowest point in the event of approximately 3 inches above instrument zero. "A" and "B" Reactor Feedwater Pumps automatically restored water level to normal. Water level was restored to normal within 1 minute of the scram. Normal water level was maintained by the level control system. No Emergency Core Cooling Systems actuated or were required to actuate to recover and/or maintain water level.

TEXT

Because the TSVs closed on the main turbine trip signal, the reactor was momentarily isolated from the Condenser (EIIS Code SQ). As a result, indicated reactor vessel steam dome pressure peaked at approximately 1111 psig about 6 seconds following the scram. The Bypass Valves (BPVs) opened to limit peak pressure and successfully controlled reactor steam dome pressure at their pressure control setpoint of 950 psig.

II. SRV SETPOINT DRIFT

During the pressure transient following the scram, no SRVs lifted. Based upon the conservative assumption that the pressure experienced by the SRVs was equivalent to reactor vessel steam dome pressure, the SRVs were possibly not in compliance with the $\pm$ 1% tolerance allowed by Unit 1 Technical Specifications Section 2.2.A.1. Therefore, the valves were removed from the main steam lines and sent to an independent laboratory for testing in accordance with ASME Boiler and Pressure Vessel Code Section XI. A tabulation of the as-found mechanical lift setpoints for the SRVs is given below:

MPL No.	Nominal Lift Pressure (psig)	Initial Lift Pressure (psig)	% Over Nominal Lift Pressure
1B21-F013A	1080	1076	(0.37)
1B21-F013B	1100	N/A*	N/A*
1B21-F013C	1100	1846**	67.82**
1B21-F013D	1090	1114	2.20
1B21-F013E	1080	1115	3.24
1B21-F013F	1090	1122	2.94
1B21-F013G	1080	1075	(0.46)
1B21-F013H	1090	1112	2.02
1B21-F013J	1100	1100	0.0
1B21-F013K	1090	1131	3.76
1B21-F013L	1080	1105	2.31

* As-received lift pressure could not be determined because the valve was inadvertently lifted with its air operator prior to the test.

** The valve did not lift during the normal scope of as-received testing in accordance with Section XI; special testing was performed to determine the resultant setpoint.

The as-received lift setpoints for 4 of the 11 SRVs were below the peak reactor vessel steam dome pressure of 1111 psig. This appears to confirm that the SRVs did not experience sufficient pressure to lift during the pressure transient following the scram. Seven of the 11 SRVs exhibited setpoint drift in excess of the $\pm$1% Technical Specifications tolerance requirement. Three of the SRVs exhibited drift in excess of the $\pm$3% tolerance specified in ASME Code Section XI.

TEXT

In general, with the exception of valve 1B21-F013C, the setpoint drift demonstrated by the SRVs is consistent with the setpoint drift experienced by other BWRs having Target Rock 2-stage SRVs. The referenced utility data are compiled by the Boiling Water Reactor Owners' Group (BWROG) in its ongoing efforts to address the issue of SRV setpoint drift by eliminating corrosion-induced bonding as a contributor.

CAUSE OF THE EVENT

I. SCRAM DUE TO COMPONENT FAILURE

The cause of the main turbine trip and reactor scram was vibration-induced component failure. Post-event calibration of EHC system Hydraulic Fluid Pressure Switch 1N32-N300 indicated its trip setpoint was 1454 psig. This is 358 psig over its as-left trip setpoint of 1096 psig set during its last calibration on 4/19/90. Physical examination of the pressure switch, which had been in service longer than 9 years, revealed its Bourdon Pressure Tube was more flexible than a pressure tube in the same model pressure switch installed in 4/90. This can cause inaccuracies in pressure readings and makes the switch more susceptible to vibration-induced pressure fluctuations. The microswitch housing was found to be more flexible than its counterpart in the newer switch. Consequently, the microswitch was more likely to move relative to the Bourdon Pressure Tube as a result of vibration. This would cause a change in the trip setpoint and/or spurious trips of the pressure switch.

From the available data, it appears vibration of the worn switch, combined with its gross setpoint drift, resulted in the main turbine trip on a low EHC system hydraulic fluid pressure signal. Post-event calibration of the "B" EHC pump's discharge pressure gage revealed it was indicating a pressure approximately 100 psi higher than actual. Therefore, pump discharge pressure was only 1500 psig, not the indicated 1600 psig. EHC accumulators, per their design, maintained system pressure at 1600 psig for the approximately 2 minutes after the "A" EHC pump was removed from service and before the main turbine tripped.

After the accumulators discharged, EHC system hydraulic fluid pressure decreased to 1500 psig, which is the "B" EHC pump's actual discharge pressure. While this was an acceptable system pressure, it was close to the actual trip setpoint of pressure switch 1N32-N300. Normal vibration of the EHC pump, in conjunction with the worn microswitch housing and Bourdon Pressure Tube, caused the pressure switch to trip and reset rapidly at the lower hydraulic fluid pressure. This can be seen from the Process Computer's (EIIS Code ID) Alarm Typer printout. The main turbine master trip relay tripped and reset 15 times over 6 seconds before the master trip solenoid valves tripped and caused the TSVs to close. The pressure switch was resetting too rapidly for the solenoid valves to reposition and cause

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the TSVs to close. Only when the pressure switch stayed in the tripped state long enough for the solenoid valves to reposition did the TSVs receive the signal to close. The rapid tripping and resetting of pressure switch 1N32-N300 also explains the flashing alarm lights. A trip of this pressure switch would cause an alarm on the bottom row of alarm panel 1H11-P650.

It is concluded the pressure switch failed due to vibration-induced wear resulting in gross setpoint drift. This condition also made the switch more susceptible to vibration-induced spurious actuations when system hydraulic fluid pressure was relatively close to its actual trip setpoint.

II. SRV SETPOINT DRIFT

The cause of the SRV setpoint drift is corrosion-induced bonding between the SRV pilot valve disc and seat. Georgia Power Company is participating in the BWROG action plan to resolve the SRV setpoint drift issue which has been concurred with by the NRC.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

I. SCRAM DUE TO COMPONENT FAILURE

This report is required per 10 CFR 50.73(a)(2)(iv) because an unplanned actuation of the RPS and Engineered Safety Features (ESFs) occurred. Specifically, the RPS actuated per design on TSV closure when the main turbine tripped. The RPS again actuated on low reactor water level when collapsing voids caused water level to decrease below the scram setpoint. The Group 2 PCIS, an ESF, received an isolation signal on low reactor water level. The Group 2 PCIVs closed per design.

The RPS automatically initiates a reactor scram to ensure the radioactive materials barriers, such as fuel cladding and the pressure system boundary, are maintained and to mitigate the consequences of transients and accidents. Closure of the TSVs, such as occurs on a main turbine trip, can result in the addition of positive reactivity to the core as the resultant reactor pressure increase collapses voids. Therefore, TSV closure initiates a scram prior to high neutron flux or high reactor pressure signals to provide a satisfactory margin to core thermal-hydraulic safety limits. The high-pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the pressure system boundary; however, the TSV closure scram provides additional margin.

In this event, the TSVs closed on a main turbine trip. The RPS actuated on TSV closure, per design. Reactor water level decreased as expected due to void collapse. However, the Reactor Feedwater Pumps responded to limit the drop in water level and restore level to its normal range. At no time was water level less than 167 inches above the top of the active fuel. Because of the quick response of the Feedwater Pumps, no Emergency Core Cooling Systems were needed to recover and/or maintain water level.

TEXT

II. SRV SETPOINT DRIFT

This report also is required per 10 CFR 50.73(a)(2)(i) because a condition prohibited by the plant's Technical Specifications potentially existed. Specifically, based on the conservative assumption that the pressure experienced by the SRVs was equivalent to reactor vessel steam dome pressure, the SRVs were potentially not in compliance with the $\pm$1% tolerance requirement of Unit 1 Technical Specifications Section 2.2.A.1. The apparent SRV setpoint drifts were in the range of 1 to 2.9%.

The purpose of the SRVs is to provide overpressurization protection for the reactor vessel and attached reactor coolant system piping. Eleven SRVs are located in the main steam lines. The SRVs are manufactured in accordance with the requirements of ASME Boiler and Pressure Vessel Code Section III for pilot-operated valves. There are three sets of valves: four valves with a nominal lift setpoint of 1080 psig, four valves with a nominal lift setpoint of 1090 psig, and three valves with a nominal lift setpoint of 1100 psig. The size of the SRVs, in conjunction with their nominal lift setpoints, is intended to limit the most severe pressure transient to +110% of the reactor vessel design pressure of 1250 psig, or a maximum of 1375 psig.

Reactor vessel steam dome pressure only reached a peak pressure of 1111 psig due to the opening of the BPVs. However, based on the conservative assumption noted earlier, it appeared the SRV tolerances were outside the 1% Technical Specifications requirement. Therefore, testing in accordance with Section XI of the Code was performed which showed the as-received setpoint for 4 SRVS was below the peak reactor vessel steam dome pressure. This indicates the pressure experienced by the SRVs was actually less than dome pressure. The differences in pressure between the reactor vessel and the main steam lines are expected and have been demonstrated in a previous analysis of the turbine trip event for Plant Hatch.

The referenced testing of the SRVs was conducted to determine the actual setpoint drift exhibited by the SRVs to assure compliance with the 1% tolerance requirement for restart of Unit 1. Seven of the eleven SRVs exhibited setpoint drift in excess of the $\pm$1% Technical Specifications tolerance requirement. Three exhibited drift in excess of the $\pm$3% tolerance specified in Section XI. All setpoint drift magnitudes were less than 4%, with the exception of one valve which would not lift during the normal scope of Section XI testing. Special testing was performed to determine its drift magnitude of approximately 68%. This valve effectively would not have opened in its self-actuating mode. However, as long as reactor pressure was greater than approximately 750 psig, it would have been possible to open the valve manually if necessary. Additionally, it should be noted that, based on BWROG SRV drift data, there have been other valves which would not open during the normal scope of Section XI testing. This is the first time additional testing has been done to determine the actual magnitude of the drift.

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A previous plant-specific analysis performed for Plant Hatch by General Electric Company demonstrates that Plant Hatch has sufficient margin for overpressure protection and that analysis bounds the SRV drift magnitudes seen in this event. Specifically, the analysis evaluated the peak vessel pressure at various setpoint drifts up to 200-psi drift for the plant's most limiting pressurization event, the MSIV closure-flux scram event. If it was conservatively assumed that all 11 SRVs opened at a lift pressure +9% over the nominal lift pressure, the resulting pressure transient would be limited to approximately 1300 psig, which is less than the design limit of 1375 psig.

Based on the previous discussion, it is concluded this event had no adverse impact on nuclear safety. The analysis is conservative in that it assumes worst-case initial conditions and is therefore applicable to all power levels.

CORRECTIVE ACTIONS

I. SCRAM DUE TO COMPONENT FAILURE

Pressure switch 1N32-N300 was replaced with a new switch. Additionally, the switch was moved off the EHC pump skid in an attempt to reduce the amount of vibration to which the switch is subjected. These actions were completed on 2/23/91.

Pressure switches 1N32-N301 and 1N32-N302, which start EHC pumps "A" and "B", respectively, on low hydraulic fluid pressure (nominal setpoint 1300 psig), also were replaced and moved off the pump skid. It was found their setpoints had drifted approximately 200 psi since their last calibration in 4/90. Consequently, it appears they may also have been adversely affected by EHC pump vibration and therefore were moved off the skid to decrease the vibration to which they were subjected. These actions were completed on 2/23/91.

The vibration levels of the Unit 2 EHC pumps were reviewed and determined to be minimal. These vibration levels will continue to be monitored. If warranted, pressure switches 2N32-N300, 2N32-N301, and 2N32-N302 will be replaced and moved in a future Unit 2 refueling outage.

II. SRV SETPOINT DRIFT

All 11 SRVs were removed, bench tested, refurbished, and reinstalled. These actions were completed by 2/22/91.

GPC will continue to be an active participant in the BWROG corrective action plan to resolve the SRV setpoint drift issue which has been concurred with by the NRC. The BWROG action plan consists of two parallel options. The primary BWROG option consists of controlling the local environment in the SRV valve cavity to mitigate corrosion. A catalyst design will be developed

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based on European experience that indicates that catalysts appear to reduce oxygen induced corrosion. It is expected that it will take about two cycles of inservice experience in selected SRVs at various BWRs to determine the effectiveness of the catalyst design. The BWROG backup option, being developed in parallel, is a safety-grade system of externally powered pressure switches to assure opening of the SRVs pneumatically when needed. This option will be available for implementation on a plant specific basis should the inservice experience with the catalyst indicate it does not resolve the issue.

As part of GPC's active participation in this BWROG program the pilot disc from the SRV which would not lift during normal Section XI testing has been supplied to General Electric for metallurgical examination of the corrosion. Significant results, if any, from this examination will be factored into the BWROG action plan. Additionally, GPC will review the results to determine the necessity for any further actions.

ADDITIONAL INFORMATION

1. Other Systems Affected:

   No systems other than RPS, PCIS, EHC, the main turbine, and the SRVs were affected by this event.

2. Previous Similar Events:

   Previous similar events in the last two years in which the reactor scrammed due to a main turbine trip were reported in LER 50-321/1990-020, dated 10/26/90, and LER 50-321/1991-001, dated 2/11/91. Corrective actions for those two events would not have prevented this event because the root causes were different. In one event, the main turbine tripped on high turbine vibration and in the other event, the turbine tripped on a main generator trip. This event is completely unrelated to those events because it was caused by a low EHC system hydraulic fluid pressure signal which is not a cause or result of main turbine vibration or a generator trip.

   Events reported in the last two years in which SRVs were found to have experienced setpoint drift were covered in LER 50-321/1990-005, dated 4/24/90, and LER 50-366/1989-007 Rev 1, dated 2/7/91. Corrective actions for those two events would not have prevented the setpoint drift seen in this event because the root causes and their corrective actions have not yet been resolved fully by the industry.

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3. Failed Component Identification:

   Master Parts List Number: 1B21-F013C, E, K
   Manufacturer: Target Rock Company
   Type: Two Stage Safety Relief Valve
   Model Number: 7567F
   Manufacturer Code: T020
   EIIS System Code: JE
   EIIS Component Code: RV
   Root Cause Code: B
   Reportable to NPRDS: Yes

   Master Parts List Number: 1N32-N300
   Manufacturer: Barksdale
   Type: Pressure Switch
   Model Number: B2T-C32-SS
   Manufacturer Code: B069
   EIIS System Code: TG
   EIIS Component Code: PS
   Root Cause Code: X
   Reportable to NPRDS: No