D. R. Madison (Dennis)
Vice President - Hatch

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SOUTHERN COMPANY
Energy to Serve Your World℠

May 2, 2008

Docket No.: 50-321

NL-08-0693

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555-0001

Edwin I. Hatch Nuclear Plant – Unit 1
Licensee Event Report
Leak in Reactor Pressure Boundary Piping Due to a
Crack Caused by Intergranular Stress Corrosion Cracking

Ladies and Gentlemen:

In accordance with the requirements of 10 CFR 50.73(a)(2)(i)(B), Southern Nuclear Operating Company is submitting the enclosed Licensee Event Report (LER) concerning a leak in the reactor coolant pressure boundary piping which was prohibited by the plant technical specification.

This letter contains no NRC commitments. If you have any questions, please advise.

Sincerely,

Dennis R. Madison

D. R. Madison
Vice President – Hatch

DRM/MJK/daj

Enclosure: LER 1-2008-001

cc: Southern Nuclear Operating Company
Mr. J. T. Gasser, Executive Vice President
Mr. D. H. Jones, Vice President – Engineering
RTYPE: CHA02.004

U. S. Nuclear Regulatory Commission
Mr. V. M. McCree, Acting Regional Administrator
Mr. R. E. Martin, NRR Project Manager – Hatch
Mr. J. A. Hickey, Senior Resident Inspector – Hatch

NRC FORM 366 (9-2007) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB: NO. 3150-0104 EXPIRES: 08/31/2010
LICENSEE EVENT REPORT (LER)	Estimated burden per response to comply with this mandatory collection request: 50 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records and FOIA/Privacy Service Branch (T-5 F52), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to infocollects@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202, (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

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4. TITLE
Leak in Reactor Pressure Boundary Piping Due To A Crack Caused by Intergranular Stress Corrosion Cracking

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO.	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER 05000
03	06	2007	2008	- 001 -	0	05	02	2008	FACILITY NAME	DOCKET NUMBER 05000

9. OPERATING MODE	11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR§: *(Check all that apply)*			
4	☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(i)(C)	☐ 50.73(a)(2)(vii)
	☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
	☐ 20.2203(a)(1)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
	☐ 20.2203(a)(2)(i)	☐ 50.36(c)(1)(i)(A)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(ix)(A)
10. POWER LEVEL	☐ 20.2203(a)(2)(ii)	☐ 50.36(c)(1)(ii)(A)	☐ 50.73(a)(2)(iv)(A)	☐ 50.73(a)(2)(x)
	☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(v)(A)	☐ 73.71(a)(4)
000	☐ 20.2203(a)(2)(iv)	☐ 50.46(a)(3)(ii)	☐ 50.73(a)(2)(v)(B)	☐ 73.71(a)(5)
	☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☐ 50.73(a)(2)(v)(C)	☐ OTHER
	☐ 20.2203(a)(2)(vi)	☒ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(v)(D)	Specify in Abstract below or in NRC Form 366A

12. LICENSEE CONTACT FOR THIS LER

FACILITY NAME	TELEPHONE NUMBER (Include Area Code)
Edwin I. Hatch / Kathy Underwood, Performance Analysis Supervisor	912-537-5931

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
B	B21	N/A	N/A	Yes					

14. SUPPLEMENTAL REPORT EXPECTED		15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
☐ YES *(If yes, complete 15. EXPECTED SUBMISSION DATE)*	☒ NO				

ABSTRACT *(Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)*

On March 6, 2008, at 0400 EST, Unit 1 was in the Cold Shutdown mode. At that time, a leak was identified in a one-inch pipe adjacent to a socket weld elbow, located between the "A" Main Steam Line (MSL) and the MSL flow instrument condensing chamber. The Technical Specification (TS) definition of pressure boundary leakage is "leakage through a non-isolable fault in the reactor coolant system." Due to its location, the leak met this definition. Based upon inspection of the weld and adjacent area, it was determined that the leak existed when the Unit was in mode 1. The TS allows no pressure boundary leakage in mode 1.

The cause of the leak is failure of the pipe due to Intergranular Stress Corrosion Cracking (IGSCC).

Corrective actions for this event included replacing the failed weld and inspection of similar piping to confirm no other leaks.

PLANT AND SYSTEM IDENTIFICATION

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

DESCRIPTION OF EVENT

On March 6, 2008, at 0400 EST, Unit 1 was in the Cold Shutdown mode. At that time, a leak was identified in a one-inch pipe adjacent to a socket weld elbow, located between the “A” Main Steam Line (MSL) and the MSL flow instrument condensing chamber (EIIS Code SB). The Technical Specification (TS) definition of pressure boundary leakage is “leakage through a non-isolable fault in the reactor coolant system.” Due to its location, the leak met this definition. Based upon inspection of the weld and adjacent area, it was determined that the leak existed when the Unit was in mode 1. The TS allows no pressure boundary leakage in mode 1. The piping was replaced and inspection of similar piping was performed to confirm no other leaks. A section of piping was removed and sent to an independent laboratory for analysis. This analysis identified the cause of the leak.

CAUSE OF EVENT

The cause of the leak is failure of the pipe due to Intergranular Stress Corrosion Cracking (IGSCC). The existence of high stress levels in stainless steel piping is a key contributor to IGSCC. A poor weld fit-up and poor weld quality, which existed from original construction, contributed to high stress in the area of the coupling joint. A weld repair which added significant extra heat into the heat-affected zone surrounding the weld had the effect of sensitizing the stainless steel material, and increasing the susceptibility to IGSCC. The weld residual stresses would also be increased by this weld repair, increasing the stress component of susceptibility. Additionally, a piping strap (restraint) shown on the isometric drawing was found missing during inspections following this failure. The absence of this strap may have resulted in increased stresses but this effect is considered less significant than the existence of stress from the poor fit-up and weld. The IGSCC failure mechanism seen in this through-wall leak is believed to be an anomaly since this mechanism is rare for small bore piping.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This report is required, per 10 CFR 50.73(a)(2)(i)(B), because a condition existed which was prohibited by the plant’s TS. The Unit 1 TS allows no pressure boundary leakage in mode 1. The discovery of a leak in a one-inch pipe adjacent to a socket weld elbow located between the “A” Main Steam Line (MSL) and the MSL flow instrument condensing chamber, and indication of spray impingement on adjacent components, led to the determination that a leak in the pressure boundary had existed for longer than allowed by the TS. Therefore, the plant was in a condition prohibited by the Unit 1 TS.

The reactor coolant system (RCS) includes systems and components that contain or transport the coolant to and from the reactor core. The pressure retaining components of the RCS and the portions of connecting systems out to and including the isolation valves define the reactor coolant pressure boundary. During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant leakage, through either normal operational wear or mechanical deterioration. Limits on RCS operational leakage are required to ensure appropriate action is taken before the integrity of the reactor coolant pressure boundary is compromised. The TS delineate the limits on the specific types of leakage.

The unidentified leakage flow limit allows time for corrective action to be taken before the reactor coolant pressure boundary can be compromised significantly. The five gallons per minute (gpm) limit is a small fraction of the calculated flow from a critical crack in the primary system piping. A critical crack is one large enough to propagate rapidly, ultimately leading to failure of the affected component. As discussed in the FSAR, crack behavior from experimental programs shows that leakage rates of over a hundred gallons per minute will precede crack instability.

In this event, unidentified leakage into the drywell averaged approximately 0.03 gpm of the allowed 5.0 gpm for the month prior to the outage. During outage activities, a leak was identified and investigated. This leak was determined to meet the TS definition of pressure boundary leakage.

At the time the unit was shut down, the unidentified leakage rate was less than one percent of the TS limit of five gpm. The leak in this event was a small hole. The pin-hole size leak is expected to be more stable than the “critical crack” (on which the TS limit is based) as evidenced by the low leakage rate. Therefore, at the time it was discovered and corrective action taken the leak was not unstable and would not have resulted in catastrophic failure of the line. However, a worst-case instantaneous and complete severing of the one-inch line, due to the presence of a pin-hole sized leak, would not result in a significant loss of reactor coolant or present any challenge to core cooling. A rupture of this one inch steam line does not result in a significant decrease in water inventory within the vessel. In addition, even if the inventory loss were completely water, the break would still be bounded by both the Loss of Coolant Accident analysis and the Feedwater Line break analysis. This proposed leak is less than 10 percent of the rated capacity of the High Pressure Coolant Injection, HPCI (EIIS Code BJ) system, which is sized to provide adequate coolant make-up for pipe breaks up to four inches, and approximates the rated capacity of the Reactor Core Isolation Cooling, RCIC (EIIS Code BN) system. It should be noted that the calculation assumed only liquid flows out of the resulting opening; in reality, a combination of liquid and vapor would flow from the break area. The actual, two-phase flow rate would be lower than that resulting from liquid only. Consequently, either system would have been capable of indefinitely maintaining normal reactor water level. Additionally, a leak of several hundred gpm would be adequately accommodated by the feedwater system (EIIS Code SJ), which has a flow rate capacity margin at rated conditions of at least 10 percent (over 2000 gpm). Therefore, any one of three diverse and independent high pressure injection systems could have provided sufficient make-up flow to maintain water level well above the top of the active fuel.

Based upon the preceding analysis, it is concluded that this event had no adverse impact on nuclear safety. This analysis is applicable to all operating conditions under which the pin-hole might have propagated to line failure.

CORRECTIVE ACTIONS

The failed weld was replaced.

Inspection of the three other similar lines was performed. No additional leaks were identified. Findings included a missing stainless steel strap on MSL's "A", “B”, and “C”. Each of these straps was replaced. Several other minor observations were made and all were corrected or evaluated as acceptable prior to startup.

Systems within the ASME Class 1 boundary were reviewed for lines which are small-bore, unisolable, and stainless steel. Sixteen Main Steam Flow connections on each unit, and the four flow measurement lines each for steam supply to RCIC and HPCI, were picked as most susceptible to IGSCC. These lines will be evaluated and corrective actions taken as determined appropriate. These actions will be tracked in the Corrective Action Program.

ADDITIONAL INFORMATION

Other Systems Affected: No systems were affected by this event other than those which have already been discussed in this report.

Failed Components Information:
Master Parts List Number: 1B21
Manufacturer: N/A
Model Number: N/A
Type: N/A
Manufacturer Code: N/A

EIIS System Code: SB
Reportable to EPIX: Yes
Root Cause Code: B
EIIS Component Code: N/A

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Commitment Information: This report does not create any permanent licensing commitments.

Previous Similar Events: One License Event Report, 2-2007-004, has been reported in the past two years in which a failure of the reactor pressure boundary has occurred. In that event a similar line experienced a high cycle fatigue induced crack, resulting in reactor pressure boundary leakage. This event occurred during the operating cycle on Unit 1 leading up to the event reported in this LER. An opportunity to implement the corrective action of inspection of the lines on Unit 1 had not occurred prior to the development of this leak. In addition upon initial inspection of the lines during the refueling outage, pressure was not present on the lines and thus the leak was not identified during the first inspection. During the reactor vessel leakage test when pressure was present on the line the leakage was identified.