NRC Form 366
(9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Brunswick Steam Electric Plant Unit 1	0 5 0 0 0 3 2 5	1 OF 1 3

TITLE (4): Nonconservative Setpoints of Steam Leak Detection Instrumentation for the RCIC Systems of Units 1 and 2 and the HPCI System of Unit 2

EVENT DATE (5)			LER NUMBER (6)				REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER		MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 6	0 6	8 8	8 8	— 0 1 4	— 0 1		0 8	3 1	8 8	Brunswick Unit 2	0 5 0 0 0 3 2 4
											0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	1 0 0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	X 50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		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
M. J. Pastva Jr., Regulatory Compliance Specialist	AREA CODE 9 1 9 4 5 7 - 2 3 1 5

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
X	B W	P T		Y		X	B J	P T		Y	
X	B W	P T		Y							

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X YES (If yes, complete EXPECTED SUBMISSION DATE)	NO		0 2	2 4	8 9

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single-space typewritten lines) (16)

At 1655 hours on 6/6/88, with both units at 100% power, respective Units 1 and 2 limiting conditions for operations (LCOs) were established as the unit's Reactor Core Isolation Cooling (RCIC) System steam leak detection instrumentation (two per unit) setpoints were determined to be set nonconservatively high. Also, at 1830 hours on 6/6/88, a Unit 2 LCO was established as the setpoint of one of the two respective instruments of the High Pressure Coolant Injection (HPCI) System was likewise determined to be in the same condition. These determinations were made during an assessment of the setpoints of the RCIC and HPCI Systems of both units. Prior to these determinations the Unit 1 HPCI was inoperable (since 5/28/88) due to failure of the E41-F001 valve (reference LER 1-88-012). Per Technical Specification 3.0.3, Units 1 and 2 reactor shutdowns were begun at 1707 and 2035 hours respectively. At 1710 hours on 6/24/88 the subject Unit 2 HPCI instrument was again determined inoperable due to the discovery of reversed low and high pressure leg piping and the HPCI System was declared inoperable. At 1102 hours on 6/30/88, LCOs were again established for Unit 1 and 2 HPCI systems due to further adjustment required to one of two steam line high flow instruments per unit.

The Unit 1 HPCI problem was corrected. The HPCI and RCIC instrument setpoints were corrected. The Unit 2 piping misconfiguration was corrected. The cause(s) of the instrument setpoint inaccuracies as well as the reversed sensing leg piping to the Unit 2 instrument have not been fully determined. A supplement to this report will be submitted by 2/24/89.

IE22
1/1

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant	0 5 0 0 0 3 2 5	8 8	— 0 1 4	— 0 1	0 2 OF 1 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Initial Conditions

Units 1 and 2 were operating at 100% power. On each unit the Reactor Core Isolation Cooling (RCIC) System (EIIS/BN), Automatic Depressurization System (ADS) (EIIS/*), Residual Heat Removal/Low Pressure Coolant Injection (RHR/LPCI) (EIIS/BO), and the A and B Core Spray (CS) subsystems (EIIS/BM) were operable and in standby readiness. On Unit 1 the High pressure Coolant Injection (HPCI) System (E41) (EIIS/BJ) was inoperable (since May 28, 1988) due to failure of the system turbine steam inlet isolation valve E41-F001 (EIIS/BJ/ISV) to open (reference LER 1-88-012). On Unit 2 the HPCI System was operable and in standby readiness.

Description of First Event

Adjustments to the HPCI and RCIC high steam flow instruments setpoints had been made in February 1988 for Unit 1 per EER 88-074 and March 1988 for Unit 2 per EER 88-018 due to identification of improper sloping of the instrument piping inside the drywell. Table 1 provides a detailed sequence of events associated with evaluation of the affect of the improper slope. General Electric (GE) was contacted to provide technical assistance in reviewing the adequacy of the original setpoints. Based on review of the information received from GE, respective Unit 1 and Unit 2 limiting conditions for operation (LCOs) were initiated, at 1655 hours on June 6, 1988, following a determination that the setpoints for the four RCIC instruments (two per unit) were high in the nonconservative direction (would actuate greater than technical specifications (T/S) requirement of ≤ 300%). In addition, at 1830 hours on June 6, 1988, a Unit 2 LCO was initiated following a determination that the setpoint of one of the two respective HPCI System instruments on Unit 2 was also set high in the nonconservative direction. The subject instrumentation are Rosemount trip units for each unit's RCIC turbine steam line, (1[2]-PDTS-N017-2 and N018-2) (EIIS/BN/PT) (Units 1 and 2) and one of the two instruments for the Unit 2 HPCI turbine steam line (2-PDTS-N005-2) (EIIS/BJ/PT). The remaining HPCI turbine steam line instruments for the units are 1-PDTS-N005-2 (Unit 1) and 1(2)-PDTS-N004-2 (Units 1 and 2).

The inoperability of both the HPCI and RCIC System requires that the unit be placed into hot shutdown within six hours per Technical Specification (T/S) 3.0.3.

At 2130 hours on May 28, 1988, the Unit 1 HPCI System had been declared inoperable due to failure of the system turbine steam supply isolation valve, E41-F001, to open (see LER 1-88-012 for more information regarding the failure of E41-F001). As a result of the existing inoperability of the Unit 1 HPCI and determination of inoperability of RCIC, at 1707 hours on June 6, 1988, a Unit 1 reactor shutdown was initiated in accordance with T/S 3.0.3. In addition, at 2035 hours on June 6, 1988, a Unit 2 reactor shutdown was initiated in accordance with T/S 3.0.3, due to the HPCI and RCIC Systems inoperability caused by the nonconservative high steam flow setpoints.

Due to the concern of shutting the units down without the availability of either high pressure injection system, enforcement discretion was requested and granted (reference June 7, 1988, submittal, BSEP/88-0618 to NRC Region II) to allow the shutdowns to be conducted without isolating the high pressure systems. Compensatory action was taken to provide isolation capability by assignment of a dedicated operator in communication with the unit Control Operator (CO). The CO monitored the steam line flow instrumentation and was to notify the on-duty CO if the instrumentation exhibited an abnormal indication. If such an indication was observed, the system would be isolated by the CO. In addition, temperature instrumentation, located in the HPCI and RCIC steam line areas, are designed to provide the isolation function on a sensed high temperature or high differential temperature.

The problem with the Unit 1 HPCI E41-F001 was corrected, HPCI was returned to standby readiness, and the shutdown of Unit 1 was secured, at 2206 hours on June 6, 1988, at a power level of approximately 20%. The setpoint for the subject Unit 2 HPCI System instrument was corrected and the shutdown of Unit 2 was secured, at 0021 hours on June 7, 1988, at a power level of approximately 31%. Following restoration of the HPCI Systems of each unit to service, the RCIC Systems were isolated and the T/S required action was continued. During the incurred power reduction on each unit no indications of a HPCI or RCIC steam line break condition were observed.

Both units were subsequently returned to full power on June 7, 1988 (Unit 2 at approximately 0800 hours and Unit 1 at approximately 1600 hours). Unit 1 RCIC was returned to service on June 10, 1988, at approximately 0400 hours and Unit 2 RCIC was returned to service on June 11, 1988, at approximately 1600 hours following readjustment of the instrument setpoints.

Description of Second Event

At 1710 hours on June 24, 1988, while performing special testing, in accordance with Special Procedure (SP)-88-026, to determine nominal values for the subject instrumentation during 100% steam flow conditions for a comparison with initial unit startup data, it was discovered that the low and high pressure leg instrument sensing lines to Unit 2 HPCI instrument E41-PDTS-N005-2 were reversed. Due to inoperability of the instrument the HPCI System was declared inoperable and an LCO was established.

Description of Third Event

On 6/30/88, during review of data taken for SP-85-026 (HPCI elbow rates d/P at near rated conditions) the setpoints for the 1 & 2 E41-PDT-N004-2 instruments were found to still be set nonconservatively. The N005-2 instruments and the four RCIC instruments were found to be set satisfactorily. The HPCI System was declared inoperable for Unit 1 and Unit 2 at 1102 hours on 6/30/88. EER 88-0329 was written to lower the setpoints to a calculated value of less than 300% steam flow based on the d/P measured at each elbow during the special test. The previous setpoints would have been conservative had the offset required by the improper sloping of the instrument lines not existed.

The fact that the N004 d/Ps were lower than the N005 d/Ps is consistent with that seen on the RCIC elbow taps, in that the lower elbows consistently had a lower d/P than the upper ones.

Cause of Each Component/System Failure or Personnel Error

There are two potential reasons for the setpoints being above the 300% allowable technical specification values. The first is that the data supplied to GE during startup testing was in error. This error could have originated from the use of the Barton differential pressure indicating switches, which had scales covering a large range. With the large range, minor divisions also covered a large range, therefore the potential for readings to be slightly in error existed.

The second reason is that the methodology used by GE in their calculations could be in error. The GE methodology is similar to the American Society of Mechanical Engineers (ASME) methodology except that a proprietary "beta" term was also used. For BSEP, a value of 1.62 was typical, and would therefore significantly increase the calculated differential pressure at 300% steam flow. It should be noted that GE now uses the ASME methodology to calculate 300% steam flow trip points, and has dropped the "beta" factor (the beta factor was not used in calculating the trip points provided to BSEP on June 6).

The specific reason for the nonconservative setpoint has not yet been determined. Special Procedures 88-025 (RCIC) and 88-026 (HPCI) have been completed and new elbow tap d/Ps were obtained. The d/P obtained during these tests were used to confirm or establish conservative setpoints for HPCI and RCIC high steam flow instruments.

As for the instrument pipe slope, these pipes were field run during construction. This was a common practice for this diameter piping at the time of plant construction.

The cause of the reversed sensing lines to the Unit 2 E41-PDTS-N005-2 instrument is presently under investigation.

Failure Mode and Affect of Each Failure

A review of the original HPCI and RCIC steam line high flow isolation instrumentation setpoints was performed. This review was to determine the actual trip point, in percent flow, of the setpoints. The table below summarizes the results.

Instrument No.	Prior Setpoint Percent Flow
1-E41-PDTS-N004-2	
1-E41-PDTS-N005-2	
1-E51-PDTS-N017-2	[illegible]
1-E51-PDTS-N018-2	388%
2-E41-PDTS-N004-2	342%
2-E41-PDTS-N005-2	382%
2-E51-PDTS-N017-2	376%
2-E51-PDTS-N018-2	437%

The percent flow for each instrument was then compared to the condition expected during the design basis double ended guillotine break (i.e., choked flow at 1120 psia). The following conditions are expected for choked flow:

System	Differential Pressure	Percent Flow
HPCI	2413 inches	1169%
RCIC	1456 inches	753%

As can be seen, the percent flow for each instrument is below the percent flow expected during a line break condition. Each instrument would have in fact isolated its respective line.

The affects this condition would have had on the environmental qualification profiles are presently being evaluated. The worst case HPCI break is the double ended guillotine break. This analysis was performed assuming 300% rated steam flow at isolation. For small steam line breaks, the initial spike would possibly have been increased, but the isolation would have occurred sooner with the higher heat input rate to the temperature switches. The overall affect of this condition is being evaluated.

System or Secondary Functions That Were Affected

The normal operation of the HPCI and RCIC Systems were not affected by the conditions discussed. These instruments are not part of the initiation logic, and would therefore not prevent the system from starting and operating.

The ability of the HPCI and RCIC Systems to isolate at less than 300% flow, however, was affected by the conditions detailed above. Though the technical specification value of 300% would have been exceeded, the setpoints would still have allowed isolation of the steam lines during the design basis double ended guillotine break. Therefore, though the isolation capability of the instruments was affected, it was not prevented.

Assessment of Event Under Reasonable and Credible Alternate Conditions

The isolation capability of the affected instrumentation was not defeated, but would be delayed. The flow expected during a double ended guillotine break is far in excess of that at which the instruments would have actually tripped and isolated the systems.

For smaller line breaks than the design basis double ended guillotine break, the temperature switches located along the lines would have operated and isolated the systems. The function and operation of these switches was not affected by the condition of the differential flow instrumentation.

The affects of this condition on the environmental profiles associated with the environmental qualification program are presently being evaluated. As discussed above, the limiting HPCI break is the double ended guillotine break. This break is analyzed at 300% rated steam flow. The fact that the high steam flow instrumentation was actually set higher than 300% could affect the environmental profile. The evaluation being performed is intended to quantify the affect on the existing profiles.

The same holds true for the small line breaks. The initial spike would be larger, but the duration of the blowdown would be shortened by the accelerated heat input. The overall affect of this condition on the environmental profiles is included in the evaluation discussed above.

Based on the above, the following conclusions have been reached:

1. Though the setpoints were in excess of the 300% allowable technical specification value, the high steam line flow instruments would have still operated to isolate the system on a design basis steam line break.

2. The performance of the temperature switches on these lines were not affected by this condition, and would still act to isolate the system.

3. A review was performed, which indicates that the environmental qualification profiles are not affected by this condition. Though the setpoints are now set less than 300%, the old setpoints would not have led to conditions worse than those for which BSEP is designed.

Corrective Actions

The following actions have been taken as a result of this issue:

1. Setpoints have been readjusted for each instrument such that isolation at less than 300% steam flow is ensured. The EER affecting each instrument is shown.

Instrument No.	Evaluation No.
1-E41-PDTS-N004-2	EER 88-0074, revision 0
	EER 88-0329, revision 0
1-E41-PDTS-N005-2	EER 88-0074, revision 0
1-E51-PDTS-N017-2	EER 88-0299, revision 0
1-E51-PDTS-N018-2	EER 88-0299, revision 0
2-E41-PDTS-N004-2	EER 88-0184, revision 0
	EER 88-0329, revision 0
2-E41-PDTS-N005-2	EER 88-0184, revision 1
2-E51-PDTS-N017-2	EER 88-0299, revision 0
2-E51-PDTS-N018-2	EER 88-0299, revision 0

2. Problem Identifications (PIDs) have been initiated to correct the instrument line slope problems. Reference PID 06156A and B.

3. Special procedures have been performed and data obtained which is being used to reverify startup differential pressures for the HPCI and RCIC steam line high flow instruments. Reference Special Procedures 88-025 and 88-026.

4. A review of the instruments setpoint histories has been initiated. This review will cover from startup to the present.

5. Research of historical documentation relative to plant startup has begun relative to the reversed sensing lines to the Unit 2 E41-PDTS-N005-2 instrument. In addition, a review of safety-related d/P instrumentation on both units has been performed to verify proper configuration of sensing lines. For instrumentation not readily verifiable by visual surveillance or other testing, additional research was performed as required to verify proper line configurations including piping walkdowns as required.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant	0 5 0 0 0 3 2 5	8 8	— 0 1 4	— 0 1	0 8 OF 1 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The following actions are in progress as a result of this event:

1. The appropriate instrument lines will be as-built during the next scheduled refueling outage which is expected to be complete on Unit 1 by February 28, 1989, and complete on Unit 2 by November 31, 1990. Any additional actions will be scheduled as required following this evolution.

2. Complete the review relative to reversed sensing lines.

3. Complete determination of the appropriate setpoints based upon the recently obtained test data.

Research of plant documentation shows this event to be an isolated reportable occurrence.

A supplement to this report updating the status of the investigation of this event will be submitted by February 24, 1989.

TABLE 1

November 5, 1987

Technical Support was notified by the Unit 2 Control Room that the standby reading for the 2-E41-PDT-N004-2 instrument was drifting up and that consequently the instrument had been declared inoperable.

November 25, 1987

Technical Support was again informed by Operations that the standby reading for the 2-E41-PDT-N004 instrument was drifting. The reading had drifted to a value of 0 inches d/P.

November 30, 1987

Following further study of the instrument lines associated with the HPCI and RCIC steam line high flow instrumentation, it was discovered that some of the lines had what appeared to be loop seals at the piping elbow tap. The isometric drawings utilized during the assessment on November 5 were prior revisions, and determined to be incorrect as to actual pipe routing. A concern was generated that a compressible leg of vapor might form between the loop seal and the high point in the line. Due to the legibility of some of the isometric drawings for these lines, the existence of the loop seals could not be absolutely verified.

Action items were assigned to resolve the concerns raised by the issue. Since access to the instrument lines could not be obtained with the units on line, the existence of the loop seals could not be verified for certain until a visual inspection of the lines could be performed.

December 2, 1987

Determination was made that the instruments were operable. This was based on several items. First, there was no reason to question the method in which the setpoints had been calculated. The GE standard methodology had been used to develop the BSEP trip points. In addition, except for the 2-E41-PDT-N004 instrument, the other instruments were reading equal to or better than the standby reading that was recorded during startup. Third, when taking into account the standy readings, the instrument setpoint would be reached prior to the GE calculated 300% trip point.

December 8, 1987

Developed Daily Surveillance Report (DSR) guidance as related to the HPCI and RCIC high steam flow instrumentation. This guidance established upper and lower bounds which would continue to ensure that the isolation occurred at a value less than or equal to 300% steam flow. These values also accounted for the standby readings for each instrument.

December 31, 1987

Initiated action to visually inspect the instrument lines associated with the HPCI and RCIC steam line high flow instruments during the upcoming outages, and to recommend corrective actions based on the outcome of those inspections.

January 10, 1988

Technical Support inspected the Unit 2 elbow tap piping for both HPCI and RCIC.

February 1, 1988

Technical Support inspected the Unit 1 elbow tap piping for both HPCI and RCIC.

February 4, 1988

Initiated a Justification for Continued Operation (JCO) for Unit 1 to provide new temporary setpoints for each of the affected instruments, along with new DSR guidelines for the new setpoints. These new setpoints were to be based on the methodology used by GE to calculate the existing trip point.

February 5, 1988

Project identification (PID) 06156A was initiated to correct the line routing concerns.

February 12, 1988

Engineering Evaluation Report (EER) 88-0074 is approved providing a justification for the continued operation of Unit 1 with the existing instrument line routing but providing revised temporary setpoints. The affect was felt to be minimal, and would have the most affect on the instrument's standby reading. New DSR values were also provided, along with the action items to reroute the piping.

March 31, 1988

EER 88-0184 is approved providing a justification for the continued operation of Unit 2 (reference BSEP/88-0618, dated June 7, 1988) with the existing instrument line routing, but providing revised temporary setpoints. These setpoints were generated utilizing the same methodology as was used for the Unit 1 JCO. New DSR values were also provided along with action items to reroute the piping.

May 26, 1988

Met with the resident NRC Inspector to discuss concerns relative to EER 88-074 (Unit 1) and EER 88-0184 (Unit 2).

May 27, 1988

A review of the prior modifications establishing the instrument setpoints (using the GE-supplied numbers) showed the calculations were based on the differential pressure across the taps, and did not utilize the actual standby readings. The value determined by the calculation was however offset by a value suitable to account for any negative standby readings. Since the effects of the loop seal would be present at all times (standby and running), it was felt that the actions taken in the setpoint revision EERs may have been overly conservative.

A review of the Unit 1 HPCI numbers was performed which showed a close correlation between the ASME methodology value of 215 inches and the GE-supplied value of 230 inches.

May 31, 1988

Continued alternate calculations and review of the Unit 2 HPCI setpoints. The HPCI N004 instrument was also close to the theoretical value. The variance of the setpoint for the HPCI N005 instrument was determined to be excessive; therefore, this instrument required a more detailed evaluation.

June 1, 1988

A review of the RCIC values showed no correlation between the ASME methodology value and the GE-supplied value. If a short radius elbow was used in the ASME calculation, the values obtained were reasonably close to the GE-supplied value. It was verified that two of the eight instruments did indeed have long radius elbows installed.

Met with the GE representative to discuss GE involvement. The main purpose initially was to review their methodology, and in particular, the meaning of the "beta" term (see EER 88-0074 and 88-0184). With this term removed from the calculation, the number obtained was reasonably close to the ASME methodology value.

June 2, 1988

GE agreed that the ASME methodology is a good way to calculate the differential pressure and that it should agree with the GE-supplied numbers.

June 6, 1988

Phone conversation with GE at approximately 1600 hours to review their draft response that addressed both HPCI and RCIC. Included in the letter were the now recommended trip points.

Discussion with GE indicated they felt that we did not have a concern with the HPCI numbers based on the old number of 230 inches, but that the RCIC numbers were not reasonably close enough to be acceptable. RCIC was therefore felt to be inoperable with the initially supplied trip points. GE also stressed that they felt the RCIC System would still trip in the event of a real steam line break as the flow would go far above the 300% trip point.

During break in conversation with GE, we discussed the fact that GE said that they used 230 inches as the originally supplied trip point for the Unit 2 HPCI System. Our records showed 292 inches as the original number for the N005 instrument.

The discussion on the use of a 230-inch trip point for the Unit 2 N005 instrument instead of the 292-inch number we had records for revealed that the information we had supplied to them had a Data Sheet marked incorrectly. This Data Sheet had been provided on June 3, 1988. It was Unit 1 information marked as Unit 2 information. GE then stated that the difference between the new GE number of 158 inches and the 292-inch number was not reasonably close and that they could not say that the Unit 2 HPCI System was operable (would trip less than 300% flow). They stressed again, however, that they felt that the system would still trip in the event of a real steam line break because the flow would go far above the 300% trip point. Consequently a decision was made to declare the Unit 2 HPCI System inoperable.

Temporary repair EER was initiated to lower the N005 setpoint to 148.5 inches. This would ensure that the setpoint met the 300% flow requirement. This evaluation was EER 88-0184, revision 1.

By midnight of June 8, 1988, the Unit 2 HPCI System was returned to operable status following the adjustment of the setpoint. It should be noted that the RCIC Systems on both units were still declared inoperable.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant	0 5 0 0 0 3 2 5	8 8	— 0 1 4	— 0 1	1 3 OF 1 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

June 9, 1988

EER 88-0299 was approved to revise the Units 1 and 2 RCIC instrument setpoints. A setpoint of 190 inches was assigned. New DSR guidelines were also supplied with the new temporary setpoints.

June 10, 1988

Unit 1 RCIC returned to service at approximately 0400 hours following readjustment of the instrument setpoints in accordance with the requirements of EER 88-0299.

June 11, 1988

Unit 2 RCIC returned to service at approximately 1600 hours following readjustment of the instrument setpoints in accordance with the requirements of EER 88-0299.

At this time, the following setpoints applied to the HPCI and RCIC steam line high flow instruments:

Instrument No.	Prior Setpoint	New Setpoint
1-E41-PDTS-N004-2	205 inches	125.50 inches*
1-E41-PDTS-N005-2	205 inches	141.75 inches
1-E51-PDTS-N017-2	387 inches	190.00 inches
1-E51-PDTS-N018-2	387 inches	190.00 inches
2-E41-PDTS-N004-2	207 inches	122.81 inches*
2-E41-PDTS-N005-2	258 inches	148.50 inches
2-E51-PDTS-N017-2	362 inches	190.00 inches
2-E51-PDTS-N018-2	491 inches	190.00 inches

*These setpoints were lowered again as a result of the data obtained during special testing.

CP&L

Carolina Power & Light Company

Brunswick Steam Electric Plant
P. O. Box 10429
Southport, NC 28461-0429

August 31, 1988

FILE: B09-13510C
SERIAL: BSEP/88-0855

10CFR50.73

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

BRUNSWICK STEAM ELECTRIC PLANT UNIT 1
DOCKET NO. 50-325
LICENSE NO. DPR-71
SUPPLEMENT TO LICENSEE EVENT REPORT 1-88-014

Gentlemen:

In accordance with Title 10 to the Code of Federal Regulations, the enclosed Supplemental Licensee Event Report is submitted. The original report fulfilled the requirement for a written report within thirty (30) days of a reportable occurrence and was submitted in accordance with the format set forth in NUREG-1022, September 1983.

Very truly yours,

J. L. Harness, General Manager
Brunswick Steam Electric Plant

MJP/jlh

Enclosure

cc: Mr. B. C. Buckley
Dr. J. N. Grace
BSEP NRC Resident Office

IE22
1/1