Indian Point 3
Nuclear Power Plant
P.O. Box 215
Buchanan, New York 10511
914 736.8001

NewYorkPower Authority

Robert J. Barrett
Site Executive Officer

May 11, 1998
IPN-98-054

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

SUBJECT: Indian Point 3 Nuclear Power Plant
Docket No. 50-286
Clarification of Commitment Regarding
<u>Auxiliary Feedwater Pump Runout Flow Protection</u>

REFERENCES:
1. NRC Bulletin 80-04, "Analysis of a PWR Main Steam Line Break with Continued Feedwater Addition," dated February 8, 1980.
2. NYPA Letter IPN-80-047, J. R. Schmieder to NRC; "Response to Bulletin 80-04," dated May 8, 1980.

Dear Sir:

The Authority is clarifying a statement previously made in response to NRC Bulletin 80-04 (Reference 1) that could be perceived as a commitment regarding operation of the Auxiliary Feedwater (AFW) System. The Bulletin required that Licensees of pressurized water reactors review the containment pressure response analysis for main steam line break inside containment. The scope of the request included a review of AFW pump runout protection.

The Authority's response (Reference 2) stated, in part:

> "Each motor-driven auxiliary feed pump is provided with a discharge pressure sustaining control system to prevent the pump from 'running out' on its curve. Runout flow conditions on the auxiliary feedwater pumps are also precluded by procedure requirements to maintain the auxiliary feedwater flow regulating valves in a throttled position. Should failure of the runout protection system result in the inoperability of the motor driven AFW pump feeding the damaged steam generator, both the other motor driven AFW pump feeding the intact generators and the steam driven AFW pump will remain operable and be available for maintaining the plant in a safe shutdown condition following the transient."

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IE11

Runout protection of the AFW pumps does not rely on the feedwater flow regulating valves being in a preset throttled position. The valves are air-operated and spring-loaded to open. Full demand from the valve control circuit results in the valve being fully closed and zero demand results in the valve being fully open. The valve control circuit consists of a remote hand controller, operated by control room operators, and a discharge pressure controller, set during periodic surveillance testing. An auctioneer device selects the higher of the two demand signals for the control signal to the valve. As long as AFW pump discharge pressure is above a preset value (nominally 1350 psig), the remote hand controller establishes the valve position. In the event that discharge pressure drops below the preset value, the discharge pressure controller will dominate and valve position will close as needed to restore discharge pressure and protect the pump from flow runout. In summary, AFW flow runout protection is based on the design of the valve control circuit and there is no requirement or commitment to maintain the valves in a throttled position. This clarification does not change the Authority's original conclusion regarding containment pressure response for main steam line break inside containment, as reported in Reference 2.

The Authority is making no new commitments in this letter. If you have any questions about this matter, please contact Mr. K. Peters at (914) 736-8029.

Very truly yours,

Robert J. Barrett
Site Executive Officer
Indian Point 3 Nuclear Power Plant

cc: Regional Administrator
U. S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Resident Inspector's Office
Indian Point Unit 3
U.S. Nuclear Regulatory Commission
P.O. Box 337
Buchanan, NY 10511

Mr. George F. Wunder, Project Manager
Project Directorate I-1
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U.S. Nuclear Regulatory Commission
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Washington, DC 20555

2/16/00

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50-286

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Subject:
Licensee Event Report 2000-001-00, Plant Outside Design Basis Due to a Mispositioned Valve Caused by a Procedure Error that Could Prevent Use of Low to High Head Safety I njection Recirculation Under Postulated Accident Conditions

A04

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IE22 - 50.73/50.9 Licensee Event Report (LER), Incident Rpt, etc.

Docket: 05000286

Indian Point 3
Nuclear Power Plant
P.O. Box 215
Buchanan, New York 10511
914 736.8001

NewYorkPower Authority

Robert J. Barrett
Site Executive Officer

February 16, 2000
IPN-00-011

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

SUBJECT: Indian Point 3 Nuclear Power Plant
Docket No. 50-286
License No. DPR-64
Licensee Event Report # 2000-001-00
Plant Outside Design Basis Due to a Mispositioned Valve Caused by a Procedure Error that Could Prevent Use of Low to High Head Safety Injection Recirculation Under Postulated Accident Conditions When Considering a Passive Failure

Dear Sir:

The attached Licensee Event Report (LER) 2000-001-00 is hereby submitted as required by 10 CFR 50.73. This event is of the type defined in 10 CFR 50.73 (a)(2)(ii)(B) for a condition recorded in the New York Power Authority's (NYPA) corrective action process as Deviation Event Report DER 00-00121.

NYPA is making no new commitments in this LER.

Very truly yours,

Robert J. Barrett
Site Executive Officer
Indian Point 3 Nuclear Power Plant

cc: See next page

IE22

cc: Mr. Hubert J. Miller
Regional Administrator
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U.S. Nuclear Regulatory Commission
Resident Inspectors' Office
Indian Point 3 Nuclear Power Plant

NRC FORM 366 (6-1998) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Indian Point 3	05000286	1 OF 5

TITLE (4)
Plant Outside Design Basis Due to a Mispositioned Valve Caused by a Procedure Error that Could Prevent Use of Low to High Head Safety Injection Recirculation Under Postulated Accident Conditions When Considering a Passive Failure

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 NAME	DOCKET NUMBER
01	17	2000	2000	-- 001 --	00	02	16	2000	N/A	05000
									N/A	05000

OPERATING MODE (9): N
POWER LEVEL (10): 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)
	20.2203(a)(1)		20.2203(a)(3)(i)	✓	50.73(a)(2)(ii)		50.73(a)(2)(x)
	20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
	20.2203(a)(2)(ii)		20.2203(a)(4)		50.73(a)(2)(iv)		OTHER
	20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Dennis Main, Operations Engineer	914-736-6205

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX

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

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On January 14, 2000, Operations discovered Safety Injection (SI) system manual butterfly valve SI-1863 mispositioned closed during an extent of condition inspection for the inability to establish excess letdown. The valve was opened shortly after discovery, the event was reviewed and the system was considered to be operable and not reportable. Further assessment of the event report on January 17 determined that the condition could potentially place the plant outside design basis and a one hour event notification was made to the NRC. FSAR Table 6.2-8 describes the use of an alternate low-to-high head SI flowpath during recirculation following a postulated accident should the normal flowpath be unavailable due to a passive failure. The inappropriate closure of valve SI-1863 could prevent the use of the alternate SI flowpath thereby placing the plant outside its design basis. The event was due to a deficiency in procedure SOP-RP-20, "Draining the Refueling Cavity," caused by personnel error as a result of inadequate error detection/self checking. The procedure did not require the valve to be returned to the Check Off List (COL) open position. Corrective actions for this event included opening valve SI-1863, issuance of a shift order for operators to review safety related procedures against their associated COL to ensure components are restored to the COL position upon completion of the procedure and the need for attention to detail, and re-performing accessible portions of safety related COLs. Procedure SOP-RP-20 will be revised prior to next use, and all safety related procedures will be reviewed to ensure they require components to be restored to the COL position. There was no effect on public health and safety.

FACILITY NAME (1)	DOCKET (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Indian Point 3	05000286	2000 --	001 --	00	2 OF 5

TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

Note: The Energy Industry identification system Codes are identified within the brackets {}

DESCRIPTION OF EVENT

On January 14, 2000, at approximately 0914 hours, with steady state reactor power at approximately 100 percent, Operations discovered Safety Injection (SI) system {BP} manual butterfly valve SI-1863 {V} mispositioned closed during an extent of condition inspection for the inability to establish excess letdown {CB}. The valve was re-positioned to open in accordance with Check Off List COL-RHR-1 shortly after discovery. The SI-1863 valve mispositioning event was recorded in a Deviation Event Report (DER 00-00121), and further investigations initiated. Initially the event was classified as potentially reportable, but after review of plant procedures and drawings, and discussion with system engineering, the condition was judged not reportable. On January 17, the event reportability determination was further assessed and the inability to perform low head (LH) {BP} to high head (HH) recirculation {BQ} with a passive failure in the alternate flow pathway was recognized. This condition could place the plant outside design basis and a one hour event notification was made to the NRC (Log No. 36598).

The finding was a result of actions initiated by Operations based on a suspicion that the inability to establish excess letdown was a result of a mispositioned valve. FSAR Table 6.2-8 describes the use of an alternate low-to-high head SI flowpath during recirculation following a postulated accident should the normal flowpath be unavailable due to a passive failure. Either set of SI containment recirculation pumps {BP} (2) or RHR pumps {BP} may be aligned to support the low head recirculation function via the RHR heat exchangers {HX}. Similarly, either set of pumps may be aligned to support the HH recirculation function through branch lines from the outlet of the RHR heat exchangers to the common suction piping of the HH SI pumps. At a time between 14 and 23.4 hours, following a loss of coolant accident (LOCA), hot leg recirculation is established by aligning the HH SI pump's discharge branch line valves to close four of eight cold leg flowpaths and open two hot leg flowpaths. The plant's design basis includes the ability to realign SI based on postulation of a passive failure 24 hours post accident. If a loss of the normal LH to HH recirculation flowpath should occur in the common HH SI suction flowpath (this would require a passive failure), then this flowpath would be isolated in accordance with established procedures. Plant design allows HH hot leg recirculation to be established using an alternate flowpath from the RHR pump discharge to the isolated suction of the 32 SI pump {P}. This alternate flowpath requires that locally operated manual valve SI-1863 be open. As a result of mispositioning valve SI-1863 closed, this alternate flowpath would not be available to operators. The procedure for aligning this flowpath in the event of a passive failure does not recognize the need to open valve SI-1863. The inappropriate closure of valve SI-1863 could prevent the use of the alternate SI flowpath in the event of a passive failure thereby placing the plant outside its design basis.

On October 8, 1999, during closure for refueling outage 10, valve SI-1863 was verified opened in accordance with Check Off List COL-RHR-1.

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TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

Subsequently, the valve was closed in accordance with procedure SOP-RP-20,"Draining the Refueling Cavity." Procedure SOP-RP-20 included a requirement to reposition the valve closed. Personnel performing SOP-RP-20 followed the procedure which required the valve to be left in the closed position contrary to COL-RHR-1. Valve SI-1863 is also identified in surveillance procedure 3PT-R34. The surveillance procedure operates the valve but leaves it in the open position in agreement with COL-RHR-1. Valve SI-1863 is assumed open when performing ONOP-ES-3, "Passive Failures During Recirculation." If procedure ONOP-ES-3 was performed with SI-1863 closed, that condition could result in starting SI pump 32 with its suction path isolated which could lead to pump failure.

An extent of condition (EOC) investigation for this event was initiated that was in addition to the existing EOC for the inability to establish excess letdown due to a mispositioned valve (DER 00-00086). The EOC for the reported event reviewed a sample of safety related procedures to determine if there are other examples of procedures that result in an as-left configuration that is contrary to the applicable COL. Safety related COLs were re-performed in all accessible areas to verify that components were positioned as directed by the applicable COL. The COLs for the remaining inaccessible safety related valves were reviewed to ensure they are in the COL required correct position and verified signed-off as in that position.

CAUSE OF EVENT

This event was due to a procedure deficiency caused by a personnel error as a result of inadequate error detection/self checking during procedure revision. System Operating Procedure SOP-RP-20 specified valve SI-1863 to be closed and failed to require the valve to be returned to the COL-RHR-1 required open position. On October 8, 1999, during closure for refueling outage 10, valve SI-1863 was verified opened in accordance with Check Off List COL-RHR-1. Subsequently, the valve was closed per refueling procedure SOP-RP-20 and left in that position contrary to COL-RHR-1. SOP-RP-20 was changed by revision 9, effective May 23, 1997, adding a new section for draining the refueling cavity using the RHR system. The new section required valve SI-1863 to be closed.

CORRECTIVE ACTIONS

The following corrective actions have been or will be performed under the New York Power Authority's corrective action program to address the cause of the event:

- Valve SI-1863 was re-positioned to open per COL-RHR-1 shortly after discovery of misposition.
- Operations issued a shift order (January 17, 2000) that included requiring the following for addressing this event; 1) procedures performed on safety related systems be checked against their associated COL to ensure the system is left in the required COL alignment, and 2) management expectations on the need for accuracy, attention to detail, and use of the "STAR" process when performing COLs.

FACILITY NAME (1)	DOCKET (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

- Procedure SOP-RP-20 was made inactive until revised prior to its next use for aligning the SI system and using SI-1863.

- Operations re-performed the plant accessible portions of all safety related COLs to ensure components were correctly positioned. Operations concluded inaccessible safety related valves (high radiation areas) were in the COL required position based on acceptable surveillance testing and proper remote indication of system operation.

- The appropriate personnel will be counseled regarding management expectations for attention to detail and the need to perform adequate error detection. Counseling of all applicable personnel is scheduled to be completed by February 29, 2000.

- All applicable safety related procedures will be reviewed to ensure components are required to be positioned in accordance with their applicable COL. The review is scheduled to be completed by December 31, 2000.

ANALYSIS OF EVENT

The event is reportable under 10 CFR 50.73 (a) (2) (ii) (B). The licensee shall report any operation or condition that resulted in the plant being in a condition that was outside the design basis of the plant.

This event meets the reporting criteria because the design basis for HH SI stated in FSAR Table 6.2-8 discusses the use of an alternate LH to HH SI flowpath during recirculation following a postulated accident should the normal flowpath be unavailable due to a passive failure. The inappropriate closure of valve SI-1863 could prevent the use of the alternate SI flowpath discussed in the FSAR. On October 10, 1999, SI-1863 was placed in the closed position in accordance with SOP-RP-20 and remained in this position until discovery on January 14, 2000, at approximately 1914 hours. Valve SI-1863 was re-positioned to open in accordance with COL-RHR-1 on January 14, shortly after discovery.

A review of Licensee Event Reports (LER) for the previous two years for events that involved safety systems outside design basis due to system operating procedural deficiencies did not identify any reported conditions. However, there was an event on October 11, 1999 (DER 99-02254), which did not meet 10CFR50.73 reporting criteria, but was a result of a procedural inadequacy that caused a valve alignment error. The event was the loss of approximately 1500 gallons of water from the reactor vessel to the containment sump as a result of a valve alignment error due to an inadequacy with procedure 3PT-R003A, "Safety Injection Test of Recirculation Switches." The cause of that event was inadequate technical review and inattention to detail regarding procedure revision which is similar to this event. A long term corrective action for that event was to revise administrative procedure AP-3, "IP-3 Procedure Preparation, Review, and Approval."

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Indian Point 3	05000286	2000	-- 001	-- 00	5 OF 5

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The revision to AP-3 was to clearly delineate management expectations regarding the process for conducting interdepartmental technical reviews, and to amplify the requirement for the review process to include verification of proper component lineups using appropriate plant drawings. This corrective action once implemented, should also address the error identified for this event. Scheduled completion is June 30, 2000. Also, as a result of DER 00-00212, procedural and drawing deficiencies are to be assessed and corrective actions identified as necessary.

SAFETY SIGNIFICANCE

This event had no effect on the health and safety of the public. There were no actual safety consequences for the event because there were no event or conditions that required mitigation.

Review of this event against the guidelines of draft NEI 99-02 Rev. D, "Regulatory Assessment Performance Indicator Guideline," concluded it was not a safety system functional failure (SSFF). In accordance with the definition of a SSFF, which NEI 99-02 states is identical to 10CFR50.73(a)(2)(v),"Any event or condition that alone could have prevented fulfillment of the safety function ...," and the guidelines of NUREG-1022 for 10CFR50.73(a)(2)(v), "In determining reportability of an event or condition that affects a system, it is not necessary to assume an additional random single failure in that system," this event was not a SSFF since there was no actual failure of an SI flow pathway. In the absence of an identified potential failure mechanism, it is not necessary to satisfy the single failure criterion for purposes of determining a SSFF. The plant design basis assumes a random passive failure to the normal pathway used for recirculation after 24 hours of an accident. The normal pathway that was assumed to have a passive failure was available and capable of performing its safety function.

There were no significant potential safety consequences of the event under reasonable and credible alternative conditions. The mispositioned condition during design basis events results in low safety significance. The Indian Point 3 design could have performed all emergency core cooling (ECCS) functions with a single active failure. The valve that was closed (i.e., SI-1863) is located in the alternate pathway for HH SI (i.e., RHR pumps to SI pumps). A single active failure would not require use of the alternate flowpath. The Indian Point 3 licensing basis does not identify or evaluate specific passive failures, but considers the loss of flowpaths due to the need to isolate in response to a passive failure. The flowpath containing valve SI-1863 would be used in response to having to isolate the normal LH to HH flowpath.

An assessment of risk was performed which assumed that HH SI was unavailable under postulated conditions. The results of the risk assessment determined that the core damage frequency (CDF) would be approximately 3E-8 per year. Assessing the condition for a period of three months (approximate duration of valve misposition) resulted in a conditional CDF (CCDF) of 7.5E-9, which is not risk significant(i.e., much less than 1E-6).

11/9/99

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50-286

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Subject:
Automatic Actuation of an Emergency Diesel Generator As a Result of In advertant Actuation of Safety Injection Relays Due to Personnel Error Caused by Poor Man-Machine Interface Design

Body:
PDR ADOCK 05000286 S

Docket: 05000286, Notes: N/A

Indian Point 3
Nuclear Power Plant
P.O. Box 215
Buchanan, New York 10511
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NewYorkPower Authority

Robert J. Barrett
Site Executive Officer

November 9 , 1999
IPN-99-119

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

SUBJECT: Indian Point 3 Nuclear Power Plant
Docket No. 50-286
License No. DPR-64
Licensee Event Report # 1999-013-00
Automatic Actuation of an Emergency Diesel Generator As a Result of Inadvertant Actuation of Safety Injection Relays Due to Personnel Error Caused by Poor Man-Machine Interface Design

Dear Sir:

The attached Licensee Event Report (LER) 1999-013-00 is hereby submitted as required by 10 CFR 50.73. This event is of the type defined in 10 CFR 50.73 (a)(2)(iv).

The Authority is making no new commitments in this LER.

Very truly yours,

Robert J. Barrett
Site Executive Officer
Indian Point 3 Nuclear Power Plant

cc: See next page

IE22

9933000031

PDR ADOCK 05000286

cc: Mr. Hubert J. Miller
Regional Administrator
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475 Allendale Road
King of Prussia, Pennsylvania 19406-1415

INPO Record Center
700 Galleria Parkway
Atlanta, Georgia 30339-5957

U.S. Nuclear Regulatory Commission
Resident Inspectors' Office
Indian Point 3 Nuclear Power Plant

NRC FORM 366 (6-1998) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Indian Point 3	05000286	1 OF 4

TITLE (4)
Automatic Actuation of an Emergency Diesel Generator as a Result of an Inadvertent Actuation of Safety Injection Relays Due to Personnel Error Caused by Poor Man-Machine Interface Design

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 NAME	DOCKET NUMBER
10	12	1999	1999	-- 013 --	00	11	09	1999		05000
										05000

OPERATING MODE (9): N
POWER LEVEL (10): 000

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

20.2201(b)	20.2203(a)(2)(v)	50.73(a)(2)(i)	50.73(a)(2)(viii)
20.2203(a)(1)	20.2203(a)(3)(i)	50.73(a)(2)(ii)	50.73(a)(2)(x)
20.2203(a)(2)(i)	20.2203(a)(3)(ii)	50.73(a)(2)(iii)	73.71
20.2203(a)(2)(ii)	20.2203(a)(4)	✓ 50.73(a)(2)(iv)	OTHER
20.2203(a)(2)(iii)	50.36(c)(1)	50.73(a)(2)(v)	Specify in Abstract below or in NRC Form 366A
20.2203(a)(2)(iv)	50.36(c)(2)	50.73(a)(2)(vii)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Richard Burroni, Instrumentation & Control Manager	(914) 736-8794

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE).	✓ NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On October 12, 1999, during a refueling outage, the 32 Emergency Diesel Generator (EDG) associated with bus 6A automatically started. EDG 32 started due to inadvertent actuation of Safety Injection (SI) relays, in the switchgear for bus 6A, during performance of blackout test 3PT-R003B. A technician performing the test was installing an electrical jumper in accordance with the test procedure when he inadvertently made up a nearby contact that actuated SI relays. The Engineered Safety Feature (ESF) equipment associated with bus 6A, including the 33 SI pump, had their electrical breakers racked into the test position for the test. Therefore, ESF equipment, including the 33 SI pump, did not start and no safety injection occurred. The EDG output breaker did not close onto bus 6A, per design, because normal (offsite) power was available. The event was due to personnel error caused by poor design (man-machine interface) in that the application of jumpers on field relays was required to fulfill the requirements of testing with relay terminal screws that are not specifically designed for the application of jumpers. Corrective action to be taken is to install relay test connectors on applicable relay terminals to facilitate surveillance testing. There was no effect on public health and safety.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Indian Point 3	05000286	1999 --	013 --	00	2 OF 4

TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

Note: The Energy Industry identification system Codes are identified within the brackets {}

DESCRIPTION OF EVENT

On October 12, 1999, at approximately 1944 hours, with the plant in cold shutdown (CSD) during a refueling outage, the 32 Emergency Diesel Generator (EDG) {EK} associated with 480 volt safety bus 6A {ED} automatically started and came up to speed. EDG 32 started due to an inadvertent actuation of Safety Injection (SI) {BQ} relays {RLY} during performance of test 3PT-R003B, "Safety Injection Test Breaker Sequencing/Bus Stripping." An Instrumentation and Control (I&C) technician performing the test was applying an alligator type jumper clip on terminal screw 14 of relay 27-6A/X3 located in 480 volt Switchgear 32 {SWGR}. As the technician was withdrawing his hand from the applied jumper, he noticed that the clip was coming off the terminal screw and he attempted to re-land the clip, but inadvertently shorted terminals 14 and 13 of relay 27-6A/X3. The shorting of terminals 14 and 13 applied a positive feed to relays 3-1/6A, SI/6A, and SI/6A1. The actuation of these relays initiated an SI sequence for 480 volt electrical safety bus 6A {BU}. In accordance with design, the load stripping sequence for bus 6A was initiated and its assigned Engineered Safety Feature (ESF) equipment including SI pump 33 sequenced as expected. The electrical breakers {BKR} associated with the ESF equipment assigned to bus 6A were racked into the test position for the test, so no ESF equipment actually closed onto bus 6A or started. Because SI pump 33 was in the test condition, no safety injection occurred. The output breaker for EDG 32 did not close onto bus 6A, per design, because normal power (offsite) was available. Equipment operated as expected in response to the event. The boundary of the safeguards initiation circuity and load sequencing is the input terminals to the relays in the switchgear.

The start of EDG 32 was discovered when Control Room {NA} Operators observed a "DG Trouble" alarm {ALM}. Indication of loss of power to Motor Control Center {MCC} 37 (the MCC-37 Auto Trip alarm), and loss of power to Battery Charger {BYC} 32 (the Battery Charger Trouble alarm) was subsequently observed. The Shift Manager was notified by operators of a loss of MCC-37 due to an inadvertent actuation of a relay during testing. Operators initiated an investigation and recovery actions. Operators placed the 32 static inverter {INVT} on backup power at 2030 hours, and then cross tied the 31 and 32 DC buses due to the loss of power from MCC-37. At 2035 hours, the 32 EDG was secured. At approximately 2157 hours, operators declared EDG 32 inoperable for performance of re-testing in accordance with test 3PT-R003B. Restoration to service of MCC-37, the 32 battery charger, and separation of DC buses 31 and 32 was completed by 2210 hours. Operations reported the event to the NRC at 2327 hours. On October 14, after completion of successful testing, operators returned the control switch for EDG 32 to automatic at approximately 0349 hours. I&C performed an investigation of the cause of the event, including an assessment of the appropriateness of current processes and capabilities to prevent inadvertent equipment operation. I&C concluded that the jumper used for this test step had adequate insulation on the clips used to terminate to the relay screws, and testing procedures were adequate.

TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

Relatively few field jumpers are used during the performance of Technical Specification (TS) required surveillance tests. However, the number and location of jumpers in the Station Blackout series of test procedures (e.g., 3PT-R003B) have increased significantly as a result of the additional testing requirements imposed by Generic Letter 96-01, "Testing of Safety-Related Logic Circuits."

CAUSE OF EVENT

This event was due to personnel error caused by poor design (man-machine interface). A test technician inadvertently shorted the terminals of a relay during testing with a test jumper and actuated SI relays. The short occurred due to poor plant design since the jumper used was determined to have adequate insulation on its clip. The cause of the event was poor plant design in that the application of jumpers on field relays was required to fulfill the requirements of testing and the relay terminal screws are not specifically designed for the application of jumpers.

CORRECTIVE ACTIONS

The following corrective actions have been or will be performed under the Authority's corrective action program to address the cause of the event:

- A meeting was conducted with I&C personnel to discuss the event and reinforce the need to be alert and aware of trip hazards.

- An extent of condition (EOC) review was performed which concluded that there is no current EOC because these types of jumpers are temporary and not left installed. Heightened awareness and installation of the test connectors are expected to prevent recurrence.

- Relay test connectors will be installed on applicable relay terminals to fulfill the necessary testing requirements of various surveillance tests. Installation of the test connectors are scheduled for refueling outage 11 (RO-11) currently planned for May 2001.

ANALYSIS OF EVENT

The event is reportable under 10 CFR 50.73 (a) (2) (iv). The licensee shall report any event or condition that resulted in a manual or automatic actuation of an Engineered Safety Feature (ESF).

This event meets the reporting criteria because the 32 EDG automatically started due to actuation of SI relays. Although EDG 32 started, it did not load onto its assigned bus 6A per design. The load stripping sequencing for bus 6A was initiated and ESF equipment sequenced per design. Because the ESF equipment electrical breakers associated with bus 6A were racked into their test position for the test, no ESF equipment started. At approximately 2035 hours, the 32 EDG was secured. At 2327 hours, operations notified the NRC of an ESF actuation (ENS Log No. 36283).

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Indian Point 3	05000286	1999	013	00	4 OF 4

TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

A review of Licensee Event Reports (LER) for the previous two years for events that involved ESF actuations due to personnel error identified the following: LER 99-003, 97-009 (7/18/97), 97-008 (7/16/97). None of these LERs involved poor design, or alligator clip jumpers specifically, and corrective actions for those events are not expected to have prevented this event.

SAFETY SIGNIFICANCE

This event had no effect on the health and safety of the public. There were no actual safety consequences for the event because there were no conditions that required mitigation. The plant responded per design to the inadvertent actuation of the SI relays. Offsite power was available and continued to power bus 6A and the redundant 480 volt safety buses (buses 5A and 2A/3A). EDG 32 started but its output breaker remained open per design because offsite power continued to energize its assigned 480 volt bus 6A. The SI actuation was not the result of plant conditions or degraded equipment but due to an inadvertent signal that actuated SI relays.

Review of this event against the guidelines of draft NEI 99-02 Rev. C, "Regulatory Assessment Performance Indicator Guideline," concluded it was not a safety system functional failure and would not be expected to impact the mitigating cornerstone concerning unavailability (i.e., high pressure safety injection, emergency AC power system, residual heat removal (RHR) system. auxiliary feedwater (AFW) system). The applicable emergency AC power source and ESF actuation circuity operated per design. The plant was in cold shutdown (CSD), therefore SI and AFW were not required to be available per TS. The EDGs were available per the TS and could have loaded upon an undervoltage condition on the safety buses. The RHR system was available in accordance with the TS. Assessment of this event under the new NRC Significance Determination Process results in a screen out (Green Item). The event did not prevent meeting a reactor safety cornerstone objective, there was no expected impact on risk, and there was no loss of system safety function.

There were no potential safety consequences of the event under reasonable and credible alternative conditions. Since the blackout test is only performed during cold shutdown conditions it is not credible or reasonable to consider this event under postulated accident conditions that are only applicable in a different plant mode. Accidents or events that could be considered applicable in shutdown are the Fuel Handling Accident, Dilution Accident, Loss of Residual Heat Removal Cooling, Loss of Spent Fuel Cooling, RCS Low Temperature Overpressure event, and Loss of Offsite Power event. TS 3.1 requires redundant decay heat removal capability in CSD, TS 3.3.A.8 requires isolation of the SI pumps to prevent injection into the RCS, and TS 3.7 requires two sources of emergency AC power. The plant was in compliance with these TS and there are procedures to mitigate these events. During this event the required equipment functioned as designed. The pending Indian Point 3 Improved TS bases state the worst case bounding events are deemed not credible in CSD and refueling because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences.

Indian Point 3
Nuclear Power Plant
P.O. Box 215
Buchanan, New York 10511
914 736.8001

New York Power Authority

Robert J. Barrett
Site Executive Officer

October 26, 1999
IPN-99-115

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

SUBJECT: Indian Point 3 Nuclear Power Plant
Docket No. 50-286
License No. DPR-64
Licensee Event Report 1999-12-00
A Common Condition Causing Multiple Core Exit Thermocouples to be Inoperable During Postulated Accident Conditions Due to Moisture Intrusion.

Dear Sir:

The attached Licensee Event Report (LER) 1999-12-00 is submitted as required by 10 CFR 50.73. This event is of the type defined in 10 CFR 50.73(a)(2)(vii).

There are no commitments being made in this LER.

Very truly yours,

Robert J. Barrett
Site Executive Officer
Indian Point 3 Nuclear Power Plant

Attachment

cc: see next page

9930800091

cc: Mr. Hubert J. Miller
Regional Administrator
Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
Kind of Prussia, Pennsylvania 19406-1415

INPO Record Center
700 Galleria Parkway
Atlanta, Georgia 30339-5957

U. S. Nuclear Regulatory Commission
Resident Inspectors' Office
Indian Point 3 Nuclear Power Plant

NRC FORM 366 (6-1998) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

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TITLE (4)
A Common Condition Causing Multiple Core Exit Thermocouples to be Inoperable During Postulated Accident Conditions Due to Moisture Intrusion

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 NAME	DOCKET NUMBER 05000
09	30	1999	1999	-- 12 --	00	10	26	1999	FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9): N
POWER LEVEL (10): 000

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)
	20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)
	20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
	20.2203(a)(2)(ii)		20.2203(a)(4)		50.73(a)(2)(iv)		OTHER
	20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iv)		50.36(c)(2)	✓	50.73(a)(2)(vii)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Richard Burroni, Instrumentation & Controls Manager	(914) 736-8794

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX
B	IP	TE	CKB Industries	N					

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

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On September 30, 1999 the unit was in cold shutdown due to a refueling outage and the core was off loaded to the spent fuel pool. It was determined that ten (10) CKB Industries safety-related core exit thermocouples would be inoperable during post accident conditions due to moisture intrusion. The exact time of the moisture intrusion condition for the thermocouples is unknown and may have occurred between the previous refueling outage and September 30, 1999. A meggar insulation resistance (IR) measurement on all Regulatory Guide 1.97 qualified thermocouples indicated that these ten thermocouples failed to meet the IR requirements. These ten (10) Regulatory Guide 1.97 thermocouples were replaced. The replacement core exit thermocouples are not manufactured by CKB Industries. This event had no effect on the health and safety of the public.

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Indian Point 3	05000286	1999 --	12 --	00	2 OF 6

TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

Description of Event

In Westinghouse Energy Systems Business Unit's Nuclear Safety Advisory Letter (NSAL) 95-006, revision 1, it was identified that in-core thermocouples manufactured by CKB Industries have exhibited moisture intrusion. This moisture intrusion was detected by insulation resistance (IR) measurements performed following hydro and hot functional testing by Westinghouse. A significant number failed to meet the IR criteria established. Subsequent examination determined that the very low IR readings were caused by leakage through the weld in the tip area.

On September 30, 1999, the unit was in cold shutdown due to a refueling outage and the core was off loaded to the spent fuel pool. In response to the concerns expressed in NSAL-95-006, revision 1, dated October 19, 1995 all core exit thermocouples were tested in order to obtain insulation resistance (IR) readings. Testing revealed the IR values were below acceptable limits for ten (10) qualified thermocouples. All of these thermocouples would be inoperable during post accident conditions due to moisture intrusion. Seven of the ten thermocouples were replaced last outage for moisture intrusion. The other three thermocouples were upgraded to RG 1.97 qualified in the last refueling outage. The exact time of the moisture intrusion condition for the thermocouples is unknown and may have occurred between Refuel Outage 9 startup (September 12, 1997) and September, 30, 1999.

The Westinghouse IR criteria for acceptance of a thermocouple during the manufacturing process is typically 10E9 ohms or higher. Since thermocouples will operate properly under normal conditions with extremely low IR, it may not be practical to reject all thermocouples below 10E9 ohms. However, to address post accident performance based on leakage in the immersed tip area, Westinghouse has developed criteria to identify the source of the moisture intrusion. Based on the recent evaluation performed on thermocouples returned from other utilities, it was evident that leakage in the tip area would significantly reduce the IR, so a value of 10E6 ohms was selected as the threshold where it could be assumed that the IR degradation was caused by leakage in the wetted area of the thermocouple and most likely the tip weld.

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TEXT CONTINUATION

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Indian Point 3	05000286	1999 --	12 --	00	3 OF 6

TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

Presently, there are 20 qualified and 35 non qualified thermocouples in use at Indian Point 3. The difference between qualified and non qualified thermocouples is not the thermocouple itself, but the type of connector at the reactor head and the wiring up to the "bed spring" from the containment penetrations. Ten (10), non-qualified, thermocouples are currently out of service.

Low voltage thermocouple systems can tolerate low IR and still perform acceptably. The primary concern is the integrity of the thermocouple when subjected to rapidly increasing post-accident temperatures and decreasing post-accident pressures.

Cause of Event

This event was caused by moisture intrusion in the core thermocouples due to leakage at the immersed tip area. This can cause core exit thermocouple failures in a post-accident condition. The thermocouples that did not meet the criteria of NSAL 95-006, revision 1 for post-accident conditions did meet the criteria for operation under normal plant operating conditions.

Corrective Action

The following corrective actions have been performed to address this event:

- Performed a meggar, insulation resistance measurement, on all twenty (20) Regulatory Guide (RG) 1.97 qualified thermocouples. Testing revealed that ten (10) RG 1.97 thermocouples had low IR readings and failed to meet the IR requirements.

- Removed the ten (10) thermocouples that had low IR readings and replaced them with thermocouples that are manufactured by Imaging and Sensing Technology. Testing was performed on these thermocouples by the manufacturer. Testing that was done included radiography of the end cap welds and IR measurements taken at room temperature, elevated temperatures, after thermal cycling, and post hydro testing. These replacement thermocouples were fitted with qualified Conax connectors to meet the requirements of RG 1.97.

- Post-installation insulation resistance measurement testing was satisfactorily performed on October 2, 1999.

TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

Analysis of Event

This event is reportable under 10 CFR 50.73(a)(2)(vii). The licensee shall report any common cause or condition resulting in independent trains or channels becoming inoperable. Ten (10) RG 1.97 core-exit thermocouples may not have met the post-accident requirements from after startup from the last refueling outage to present due to the possibility of their not operating as designed during post-accident conditions.

Based on Westinghouse limited testing as described in their NSAL 95-006, revision 1, even if the thermocouples burst, they may still provide an adequate measurement. This potentially degraded condition my have degraded the digital subcooling margin monitor which uses the core-exit thermocouples as an input and is also used for emergency operating procedures. This was due to the possibility that these core exit thermocouples may not have operated as designed during the postulated accident condition.

A review of the past two years of Licensee Event Reports (LER) indicates that LER 97-012-00 indicates a similar condition occurred where a manufacturer defect rendered multiple trains or channels inoperable. This LER was for multiple core exit thermocouples to be inoperable during postulated accident conditions due to moisture intrusion.

Safety Significance

The core-exit thermocouples are not subject to the condition discussed in this event during normal plant operations and would have performed all their design functions for past plant operations. Therefore, there was no effect on the health and safety of the public for actual past plant operations. It is believed that for the postulated accidents causing the conditions discussed in this event that there is no significant effect on the health and safety of the public based on the following information/analysis from the Westinghouse NSAL 95-006, Revision 1:

Issues with leakage in the tip area of the in-core thermocouples are corrosion and bursting. Corrosion of the lead wires requires sufficient exposure time to temperatures above 500^{0}C and therefore should not be a problem at either normal or accident conditions. Although postulated accident temperature may exceed 500^{0}C, such temperature would exist for a limited time. Other sources indicate

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TEXT CONTINUATION

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TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

that under these conditions the corrosion depth is limited to 5 mils (lead wire diameter is 20 mils). Westinghouse also evaluated bursting of the thermocouple sheath due to rapidly increasing temperatures and decreasing pressures during post-accident conditions. This caused "flashing" of the trapped moisture. Three thermocouples with low IR were subjected to an extreme test where the tip was exposed to an instantaneous change from room temperature to 2000^{0}F. Two of the three burst but did not break the lead wire. Even if the thermocouples burst, they may still provide an adequate measurement.

The conditions under which the thermocouples could fail would only occur during a severe core heatup (above 1000^{0}F). Typically, there are only two accidents that would result in such high core temperatures - an inadequate core cooling (ICC) scenario (which is beyond the design basis of the plant) and the design basis small Loss of Coolant Accident (LOCA) scenario. The ICC scenario is a loss of coolant scenario for which there is no makeup to the primary system.

As the core heats up, the operator will perform recovery actions to restore Safety Injection (SI) flow and dump steam to reduce Reactor Coolant System (RCS) pressure (which can result in accumulator injection). Also, the operator may try to start Reactor Coolant Pumps (RCPs) to provide forced cooling in the core and to open a pressurizer Power Operated Relief Valve (PORV) to further depressurize the RCS. If any of these actions are successful in restoring core cooling, the operator will return to performing the normal recovery actions. If none of the actions are successful, the operator will eventually transition to the Severe Accident Management Guidelines to mitigate fission products that are released from the overheated core.

Note: Severe Accident Management enhancements were implemented at Indian Point Unit 3 on December 31, 1998 as previously committed in NYPA Letter IPN-95-040, dated March 28, 1995.

If during the core heatup some of the thermocouples fail, the operator should still have adequate indication from the remaining core exit thermocouples that the actions are either successful or have failed in restoring core cooling. Since the hotter thermocouples will fail first, the operator may not have the indication of the hottest core temperature. However, the downward trend of the core exit thermocouples should be adequate in determining the success of the recovery strategies.

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TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

If all of the thermocouples fail during the heatup, the operator will not have an indication as to whether the recovery actions have successfully restored core cooling. Note that the maximum temperature expected during the design basis small break LOCA would be in the 1200 to 1300 ^{0}F range for a very short period of time (less than a few minutes). Therefore the operator may continue to perform recovery actions needlessly. Although these recovery actions are not detrimental to the safety of the plant, they could result in needless damage to plant equipment. An example would be starting an RCP in highly voided conditions during the worst point of the small break LOCA, which could destroy the pump.

A failure of some of the core exit thermocouples during an accident with high core temperatures will not jeopardize plant safety. Although the complete failure of thermocouples will not jeopardize plant safety for the design basis small break LOCA or the ICC scenario, it would complicate the recovery and could result in unnecessary damage to plant equipment.

Power Authority's Alternate Equipment Available:

Based on Westinghouse limited testing as described in NSAL 95-006, revision 1, even if the thermocouples burst, they may still provide an adequate measurement. In addition, the Reactor Vessel Level Indicating System (RVLIS) provides a means to monitor the water level in the reactor vessel during a postulated accident, although secondary in use to the thermocouples in the emergency operating procedures. It is designed to function under all normal, abnormal, accident and post-accident conditions concurrent with seismic events. The RVLIS consists of two redundant trains, with redundant power supplies, which automatically compensate for variation in fluid density as well as for the effects of reactor coolant pump operation. This system was installed in response to NUREG-0737, Item II.F.2 and RG 1.97 as a diverse means to detect inadequate core cooling. In accordance with the Technical Specifications RVLIS was operable from September 12, 1997 through September 10, 1999.

FACILITY NAME (1)	DOCKET (2)	LER NUMBER (6)			PAGE (3)
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Indian Point 3	05000286	1999 --	12 --	00	6 OF 6

TEXT *(If more space is required, use additional copies of NRC Form 366A)* **(17)**

If all of the thermocouples fail during the heatup, the operator will not have an indication as to whether the recovery actions have successfully restored core cooling. Note that the maximum temperature expected during the design basis small break LOCA would be in the 1200 to 1300 ^{0}F range for a very short period of time (less than a few minutes). Therefore the operator may continue to perform recovery actions needlessly. Although these recovery actions are not detrimental to the safety of the plant, they could result in needless damage to plant equipment. An example would be starting an RCP in highly voided conditions during the worst point of the small break LOCA, which could destroy the pump.

A failure of some of the core exit thermocouples during an accident with high core temperatures will not jeopardize plant safety. Although the complete failure of thermocouples will not jeopardize plant safety for the design basis small break LOCA or the ICC scenario, it would complicate the recovery and could result in unnecessary damage to plant equipment.

Power Authority's Alternate Equipment Available:

Based on Westinghouse limited testing as described in NSAL 95-006, revision 1, even if the thermocouples burst, they may still provide an adequate measurement. In addition, the Reactor Vessel Level Indicating System (RVLIS) provides a means to monitor the water level in the reactor vessel during a postulated accident, although secondary in use to the thermocouples in the emergency operating procedures. It is designed to function under all normal, abnormal, accident and post-accident conditions concurrent with seismic events. The RVLIS consists of two redundant trains, with redundant power supplies, which automatically compensate for variation in fluid density as well as for the effects of reactor coolant pump operation. This system was installed in response to NUREG-0737, Item II.F.2 and RG 1.97 as a diverse means to detect inadequate core cooling. In accordance with the Technical Specification Table 3.5-5, one train of RVLIS is required to be operable above cold shutdown (greater than 200 degrees F). During the period of September 12, 1997 through September 10, 1999, based on a documentation review, there were no instances identified of more than one train of RVLIS out of service.

Indian Point 3
Nuclear Power Plant
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NewYorkPower Authority

Robert J. Barrett
Site Executive Officer

October 26, 1999
IPN-99-116

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

SUBJECT: Indian Point 3 Nuclear Power Plant
Docket No. 50-286
License No. DPR-64
Withdrawal of Relief Request for Reactor Vessel Nozzle Inspections

Reference: 1. NYPA letter to the NRC, "Relief Request for Reactor Vessel Nozzle Inspections," IPN-99-088, dated August 18, 1999.

Dear Sir:

The purpose of this letter is to withdraw the relief request submitted in Reference 1. In Reference 1, the Authority requested the NRC to grant relief from the inspection requirements of ASME Code Section XI, for the volumetric examination of the inner radius section of the reactor vessel nozzles. This inspection was required to be performed during refueling outage RO 10.

The Authority has performed the required inspection during RO 10 and the relief is no longer needed. The next inspection is required to be performed during the next (third) 10-year inservice inspection interval and the Authority will resubmit the relief request, if required, as part of the Inservice Inspection Program submittal for the third 10-year interval. Therefore, the Authority hereby withdraws the relief request submitted in Reference 1.

The Authority is making no new commitments in this submittal. Should you have any questions regarding this matter, please contact Mr. K. Peters at (914) 736-8029.

Very truly yours,

Robert J. Barrett
Site Executive Officer

cc: see next page

cc: Mr. Hubert J. Miller
Regional Administrator
Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Resident Inspector's Office
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Mr. George F. Wunder, Project Manager
Project Directorate I
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NewYorkPower Authority

Robert J. Barrett
Site Executive Officer

October 15, 1999
IPN-99-111

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

SUBJECT: Indian Point 3 Nuclear Power Plant
Docket No. 50-286
License No. DPR-64
Licensee Event Report # 1999-011-00
Pressurizer Safety Valves Inoperable with the Reactor Vessel Head On Without an Equivalent Opening of One Valve Flange Established Due to Inadequate Communications;
A Condition Prohibited by Technical Specifications

Dear Sir:

The attached Licensee Event Report (LER) 1999-011-00 is hereby submitted as required by 10 CFR 50.73. This event is of the type defined in 10 CFR 50.73 (a)(2)(i)(B).

The Authority is making no new commitments in this LER.

Very truly yours,

Robert J. Barrett
Site Executive Officer
Indian Point 3 Nuclear Power Plant

cc: See next page

9910[illegible]
9930600 38

cc: Mr. Hubert J. Miller
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U.S. Nuclear Regulatory Commission
Resident Inspectors' Office
Indian Point 3 Nuclear Power Plant

NRC FORM 366 (6-1998) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

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TITLE (4)
Pressurizer Safety Valves Inoperable with the Reactor Vessel Head On Without an Equivalent Opening of One Valve Flange Established Due to Inadequate Communications; A Condition Prohibited by Technical Specifications

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 NAME	DOCKET NUMBER
09	16	1999	1999	-- 011 --	00	10	15	1999		05000
									FACILITY NAME	DOCKET NUMBER
										05000

OPERATING MODE (9): N

POWER LEVEL (10): 000

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.2201(b)		20.2203(a)(2)(v)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)
	20.2203(a)(1)		20.2203(a)(3)(i)		50.73(a)(2)(ii)		50.73(a)(2)(x)
	20.2203(a)(2)(i)		20.2203(a)(3)(ii)		50.73(a)(2)(iii)		73.71
	20.2203(a)(2)(ii)		20.2203(a)(4)		50.73(a)(2)(iv)		OTHER
	20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		Specify in Abstract below or in NRC Form 366A
	20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Tom McKee, Operations Engineer	(914) 736-8349

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX

SUPPLEMENTAL REPORT EXPECTED (14)

				EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE).	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On September 16, 1999, while in cold shutdown (CSD) during preparations for refueling, the assistant operations manager discovered that the pressurizer safety valves (SV) had all but two of their bolts removed from their associated flanges prior to the reactor vessel head being removed. Technical Specification (TS) 3.1.A.2.a requires that at least one pressurizer code SV be operable or that there be an opening greater than or equal to the size of one code SV flange to allow for pressure relief, whenever the reactor head is on the vessel. The reactor vessel head was fully detensioned, but with some bolts of the pressurizer SVs removed the SVs were considered inoperable and an equivalent opening was not available. The cause of the inoperable SVs was inadequate verbal communication due to misunderstanding. Maintenance requested from work control (WC) and believed they received permission to de-tension the SVs, but WC believed they only authorized removal of their whip restraints. Corrective actions include removal of one SV to establish the required reactor coolant system opening, and counseling appropriate personnel on management's expectations for attention to detail and the need to perform adequate communications. The procedure on Outage Management will be revised to ensure changes in work sequences require assessment for impact of TS requirements. The requirements of TS 3.1.A.2.a are to be relocated to the FSAR when the current TS are revised to the improved TS (ITS) which does not have this requirement in CSD. The event had no effect on public health and safety. This event was not considered a safety system functional failure in accordance with Nuclear Energy Institute guideline NEI 99-02.

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Note: The Energy Industry identification system Codes are identified within the brackets {}.

DESCRIPTION OF EVENT

On September 16, 1999, at approximately 1300 hours, with the plant in cold shutdown (CSD) during preparations for scheduled refueling activities, the assistant operations manager (AOM) discovered at an outage meeting that the pressurizer {PZR} code safety valves (SV) {RV} had all but two of their bolts removed from their associated flanges {PSF} prior to the reactor vessel {RPV} head being removed. The operations shift manager (SM) was notified of the condition at approximately 1400 hours and a confirmation of operability determination (COD) and immediate corrective actions were initiated. Technical Specification (TS) 3.1.A.2.a requires that at least one pressurizer code SV be operable or that there be an opening greater than or equal to the size of one code SV flange {PSF} to allow for pressure relief, whenever the reactor head is on the vessel. Reactor vessel head detensioning was initiated on September 15, at 1530 hours, and fully detensioned at 2230 hours. Both Power Operated Relief Valves (PORVs) were open prior to this event with one PORV blocked open to ensure the required equivalent opening per Overpressure Protection System (OPS) {AB} TS 3.1.A.8. At 1730 hours, a pressurizer code SV was lifted (removed) providing the required TS opening. A deviation event report (DER 99-01912) recorded the condition and investigations initiated. On September 20, 1999, at 1100 hours, System Engineering (SE) completed the COD confirming that the SVs were inoperable. The COD concluded that with some bolts of the pressurizer SVs removed the SVs were inoperable since they could not meet the operability definition of properly installed in the system and capable of performing the intended function in the intended manner. Also, with some bolts remaining intact the SVs could not be credited with providing the required opening for pressure relief in the intended manner.

Further investigation determined that the original outage schedule planned to remove the pressurizer manway prior to removing the pressurizer SVs, thus meeting the TS requirement for a vent opening equivelent to a SV flange. On September 15, a maintenance supervisor determined that work to remove the SVs could be started ahead of schedule because the required tool to remove them became available at the work site ahead of schedule. The maintenance supervisor met with outage management and requested permission to remove the SV ahead of schedule. The removal of the SVs along with other activities were discussed including the removal of the SV whip restraints. The meeting attendees included a licensed operator in work control, a planner and the maintenance job supervisor. The meeting included discussion of removing the pressurizer manway, tools (Hy-Torque), SV restraints and potential interferences. The maintenance supervisor left the meeting believing outage management gave permission to remove the SVs. Outage management believed they had only given permission to remove the SV whip restraints while unbolting the pressurizer manway and that the schedule sequence for removing the manway and then the SVs would be followed. No pre-job brief was performed for the clearance to conduct the revised schedule work and no schedule impact sheet was used. Operations verified the Protective Tagging Order (PTO) and clearance for the work and gave permission to proceed.

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On September 15, work was started to detension the pressurizer SV flange hold down bolts. Two of the three SVs had all but two of their flange hold down bolts detensioned and removed and the third SV had all but two of its flange hold down bolts detensioned and removed on September 16.

On September 16, at approximately 1300 hours, the mechanical maintenance supervisor provided the status of maintenance work at the daily outage meeting that included the work on the pressurizer SVs. A System Engineering supervisor at the meeting recognized that the condition of the pressurizer SVs were prohibited by the TS and advised the AOM. Subsequently the AOM advised the SM of the condition.

The Reactor Coolant System (RCS) {AB} is overpressure protected by three (3) ASME Code SV (PCV-464, 466, 468) and two PORVs {RV} (PCV-455C and PCV-456) located on top of the pressurizer. The three code SVs protect the reactor coolant pressure boundary from overpressure during abnormal operating pressure and temperature conditions in accordance with the ASME Boiler & Pressure Vessel Code. The pressurizer code SV's are spring loaded, enclosed pop type, self actuated angle relief valves {RV} with backpressure compensation. The code SV do not provide cold overpressurization protection because their lift setpoints are fixed at too high a value to prevent a potential brittle fracture of the reactor vessel. Cold overpressurization protection of the reactor vessel in CSD is provided by the PORVs. The TS basis states that one SV provides adequate protection during CSD for overpressurization if no residual heat were removed by the Residual Heat Removal (RHR) System {BP} because the amount of steam which could be generated at SV relief pressure would be less than half the capacity of a single valve.

An extent of condition review determined that other miscommunications have resulted in errors during the current outage and similar events have occurred previously. Review findings will be assessed and any corrective actions performed as required under the Authority's corrective action program.

CAUSE OF EVENT

The cause of the inoperable pressurizer code SVs that resulted in a TS prohibited condition was misunderstanding due to inadequate verbal communication. Maintenance requested from work control (WC) and believed they received permission to detension the SVs, but WC believed they only authorized removal of their whip restraints. Review of the actions to unbolt the SVs under the outage work control process failed to ensure that work would be performed so that one SV would remain operable or an equivalent opening would be provided in accordance with the TS.

The event would not be a TS prohibited condition under the improved TS (ITS). TS 3.1.A.2.a was an original specification requirement based on consideration of RCS pressurization if no decay heat were removed from the RCS via the RHR system in CSD. A single SV provided the capacity to relieve pressure from such a condition in CSD. The OPS per the current TS 3.1.A.8 [i.e., Low Temperature Overpressure Protection System (LTOPS)], which includes the PORVs, provides cold overpressurization protection and is retained in the ITS.

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CORRECTIVE ACTIONS

The following corrective actions have been or will be performed under the Authority's corrective action program to address the causes of this event.

- A pressurizer SV was removed to establish the required reactor coolant system opening for conformance with the TS.

- The administrative procedure on Outage Management will be revised to ensure that changes to the sequences of work require assessment of the impact of TS requirements. The procedure is scheduled to be revised by the end of January 2000.

- The appropriate personnel were counseled on management's expectations for attention to detail and the need to perform adequate communications.

- TS 3.1.A.2.a will be deleted and the requirement relocated to the FSAR when the current TS are revised to the improved TS (ITS). Changes to the TS requirements are awaiting NRC approval and implementation of the ITS. ITS Section 3.4.10 maintains the current TS 3.1.A.2 in Modes 1,2, 3, and in Mode 4 when above the LTOP arming temperature. ITS LCO 3.4.10 does not include any requirements for pressurizer code SVs below the LTOP arming temperature.

ANALYSIS OF EVENT

The event is reportable under 10 CFR 50.73 (a) (2) (i) (B). The licensee shall report any operation or condition prohibited by the plant's Technical Specifications.

This event meets the reporting criteria because a pressurizer code SV was not operable and an opening greater than or equal to the size of one code SV flange was not available with the reactor head on the vessel while in CSD. The code SVs are designed to be operable with all bolts properly installed. TS 1.5 defines operable as properly installed in the system and capable of performing the intended functions in the intended manner as verified by testing and tested at the frequency required by the TS. With some of each SV's flange hold down bolts unbolted the SVs became inoperable. TS 3.1.A.2.a specifies that at least one pressurizer code SV shall be operable, or an opening greater than or equal to the size of one code SV flange to allow for pressure relief, whenever the reactor head is on the vessel except for hydrostatically testing the RCS in accordance with Section XI of the ASME B&PV Code. With the code SVs inoperable and the reactor head on the vessel, the plant was in a condition prohibited by TS 3.1.A.2.a. RCS cold overpressure protection was available during the event time by the OPS under TS 3.1.A.8. The PORVs were open which provided an overpressure relief opening.

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The condition existed from the time the last code SV was unbolted (September 16, at approximately 1200 hours) to the time a code SV was removed and the TS required equivalent opening provided (September 16, at approximately 1730 hours).

A review of the past two years of Licensee Event Reports (LER) for events that involved TS prohibited conditions due to inoperable TS components as a result of personnel error identified LER 97-017 and LER 97-028. LER 97-017 reported OPS inoperable due to inadequate procedural guidance for verifying operability. Corrective actions (CA) for that event would not have prevented this event because operability verification prior to LCO/PTO closeout was not the cause of this event. LER 97-028 reported alignment of the safety injection (SI) system {BQ} for testing contrary to the TS due to misapplication of the TS as a result of a lack of knowledge by operators. The CAs would not have prevented this event because the cause was different. Operators during this event understood the TS requirement but failed to ensure the proper sequencing of work. An additional review of the previous two years of LERs for events that involved inadequate TS identified LER 98-005-01, LER 98-008, LER 99-004, and LER 97-032-02. These LERs reported inoperable component conditions that had no TS allowed outage time (AOT) specified. CA for these events did not prevent this event because the TS have not been converted to the ITS. Specifying AOTs for those TS systems and components missing them would not have corrected TS 3.1.A.2.a. A CA to change to the ITS would not have prevented this event but would not have resulted in a TS prohibited condition.

SAFETY SIGNIFICANCE

This event had no effect on the health and safety of the public.

Review of this event against the guidelines of draft NEI 99-02 Rev. B, "Regulatory Assessment Performance Indicator Guideline," concluded it was not a safety system functional failure (SSFF) for the functional area of Primary System Safety and Relief. Although the code SV were inoperable and did not meet the TS limiting condition for operation, the safety function of RCS pressure relief could have been performed. The code SV function of RCS pressure relief during CSD would have been performed by the PORVs of the OPS and by limiting the mass and heat input transients capable of overpressurizing the RCS [e.g., isolating the SI pumps preventing the capability of injection into the RCS (TS 3.3.A.8), isolating the accumulators, and disallowing start of a Reactor Coolant Pump (RCP)]. Analysis demonstrate that either one PORV or the depressurized RCS and an RCS vent of two square inches, which is equivalent to one PORV, can maintain RCS pressure below limits when no SI pump is capable of injecting into the RCS. No TS, design or code limit was or could be exceeded. Adequate RCS pressure relief remained functional because a PORV was blocked open providing the required pressure relief opening in accordance with TS 3.1.A.8. Also, in accordance with the NEI guidelines it is not necessary to consider a single random failure, absent an identified potential failure mechanism. No potential failure mechanism was identified for the components in the pressure relieving pathway and the open PORV pathways would be expected to perform their safety function and relieve an overpressure condition.

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There were no actual safety consequences for the event because there were no events requiring pressure relief of the RCS. The RCS had two open PORVs with one blocked open providing the required cold overpressure relief pathway in accordance with TS 3.1.A.8. Redundant decay heat removal was available per TS 3.3.A.7 and an operating RHR loop was connected to the RCS providing core cooling that would prevent RCS heatup and pressurization. Also, the RCS was at reduced inventory providing additional margin to any pressurization events.

There were no potential safety consequences of this event. The required pressure relief opening was available because a PORV was blocked open in accordance with TS 3.1.A.8, and mass and heat input events were disallowed by administrate control [e.g., SI pumps rendered incapable of injection into the RCS per TS 3.3.A.8, accumulators isolated , and RCP operation prevented per TS 3.1.A.h by positioning controls to prevent starting]. The RHR system was operable and in service providing RCS cooling. The RHR system is protected from overpressure by a spring loaded relief valve which has sufficient capacity to accommodate all three charging pumps. Although the TS require one pressurizer SV to be operable in CSD when the reactor vessel head is on, the code SV do not provide cold overpressurization protection because their lift setpoints are fixed at too high a value to prevent a potential brittle fracture of the reactor vessel. The ITS do not have a requirement for the SV to be operable in the CSD condition. The ITS do have a requirement for PORVs to provide protection from cold overpressurization of the reactor vessel when the RCS is in CSD. The OPS, which was operable with the PORVs is designed to prevent overpressurization of the reactor vessel when the RCS is at low temperatures.

FSAR Section 4.2.3 states that the pressurizer PORVs operate from the OPS to prevent RCS pressure from exceeding 10CFR50, Appendix G stress limits given in the TS, and the limits of ASME Section III Code Case N-514. The Indian Point 3 specific analysis for the LTOP system identifies bounding events which were previously identified in a Westinghouse Owners Group (WOG) OPS study based on the mechanisms for increasing the RCS pressure at CSD conditions. The bounding heat addition event identified was the start of one RCP, with the steam generators at an elevated temperature (loop temperature asymmetry). The WOG study concluded that a core decay heat addition (loss of RHR) was not as significant as a loop temperature asymmetry and therefore is bounded by the loop temperature asymmetry event. Therefore, LTOPS will satisfy TS 3.1.A.2.a because the basis of TS 3.1.A.2.a is a loss of RHR event which is bounded by the LTOP analysis for a loop temperature asymmetry event.

In addition, with no SVs operable, an operating RHR loop, connected to the RCS, provides core cooling to prevent RCS heatup and pressurization. During this event both PORVs were open; one was open with nitrogen and one was blocked. Had a single failure occurred to a PORV (nitrogen opened), the redundant PORV would provide the pressure relief capability. In the event a PORV leaks or sticks open after actuation, normally open motor operated stop valves are provided upstream of the PORVs to prevent flow. Also, a redundant train of RHR was operable and available in accordance with TS requirements to maintain core cooling and prevent RCS heatup and pressurization.