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Robert J. Barrett
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July 5, 2002
IPN-02-056

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 # 2002-001-00
Operation in a Condition Prohibited by Technical Specifications Due to an Inoperable Service Water Pipe Caused by a Leak that Exceeded the Allowed Outage Time

Dear Sir:

The attached Licensee Event Report (LER) 2002-001-00 is hereby submitted as required by 10 CFR 50.73. This event is of the type defined in 10 CFR 50.73 (a)(2)(i)(B) for a condition recorded in Entergy's corrective action process as Condition Report CR-IP3-2002-02093.

Entergy is making no new commitments in this LER.

Very truly yours,

Robert J. Barrett
Vice President Operations
Indian Point 3 Nuclear Power Plant

cc: See next page

IE22

cc: Mr. Hubert J. Miller
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NRC FORM 366 (7-2001) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104 EXPIRES 7-31-2004

Estimated burden per response to comply with this mandatory information collection request: 50 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the Records Management Branch (T-6 E6), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to bjs1@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202 (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

LICENSEE EVENT REPORT (LER)

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

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4. TITLE

Operation in a Condition Prohibited by Technical Specifications Due to an Inoperable Service Water Pipe Caused by a Leak that Exceeded the AOT

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MO	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO	MO	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
06	07	2002	2002	– 001 –	00	07	05	2002		05000
									FACILITY NAME	DOCKET NUMBER
										05000

9. OPERATING MODE	1
10. POWER LEVEL	100

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check all that apply)

20.2201(b)		20.2203(a)(3)(ii)		50.73(a)(2)(ii)(B)		50.73(a)(2)(ix)(A)	
20.2201(d)		20.2203(a)(4)		50.73(a)(2)(iii)		50.73(a)(2)(x)	
20.2203(a)(1)		50.36(c)(1)(I)(A)		50.73(a)(2)(iv)(A)		73.71(a)(4)	
20.2203(a)(2)(I)		50.36(c)(1)(ii)(A)		50.73(a)(2)(v)(A)		73.71(a)(5)	
20.2203(a)(2)(ii)		50.36(c)(2)		50.73(a)(2)(v)(B)		OTHER Specify in Abstract below or in NRC Form 366A	
20.2203(a)(2)(iii)		50.46(a)(3)(ii)		50.73(a)(2)(v)(C)			
20.2203(a)(2)(iv)		50.73(a)(2)(I)(A)		50.73(a)(2)(v)(D)			
20.2203(a)(2)(v)	✓	50.73(a)(2)(I)(B)		50.73(a)(2)(vii)			
20.2203(a)(2)(vi)		50.73(a)(2)(I)(C)		50.73(a)(2)(viii)(A)			
20.2203(a)(3)(I)		50.73(a)(2)(ii)(A)		50.73(a)(2)(viii)(B)			

12. LICENSEE CONTACT FOR THIS LER

NAME	TELEPHONE NUMBER (Include Area Code)
Tom Orlando, Programs & Component Engineering Manager	914-736-8340

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

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX
X	BI	PSP	W120	Y					

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

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

On June 5, 2002, during routine rounds, Operations identified a leak in a 18 inch diameter service water (SW) supply header pipe in the Primary Auxiliary Building (PAB). Engineering inspected the leaking pipe and initiated non-destructive examinations to characterize the extent of the degradation. Additional testing was performed on June 6, and on June 7 further testing and an evaluation of collected data was performed. A plan of action was developed and the NRC notified. On June 7, at 2035 hours, Engineering concluded the pipe was inoperable. Operations entered SW Technical Specification 3.7.9.E.1 Action Statement (AS) with a 12 hour completion time and closed valves to isolate the leaking pipe. Code repair of the pipe was initiated and because the repair time would exceed the SW TS AOT, a notice of enforcement discretion (NOED) was prepared and a request for an additional 60 hours was submitted to the NRC. The NOED was authorized prior to exceeding the TS AOT, pipe repairs completed and the SWS returned to operable on June 9, 2002, after approximately 44.5 hours. The cause of the pipe leak was corrosion of the carbon steel weld metal at the butt weld of the 18 inch diameter pipe. Corrective actions were a code repair of the pipe and an assessment of the existing program for Generic Letter 89-13 with adjustments that include radiographic testing of four additional weld locations of similar pipe size and flow characteristics prior to refueling outage 12 scheduled in March 2003. The event had no effect on public health and safety.

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 June 5, 2002, at approximately 1645 hours, while at 100% steady state reactor power, a nuclear plant operator (NPO) discovered a small leak (approximately 1 drop per second) in an 18 inch diameter service water system (SWS) {BI} essential SW header pipe (line number 408) {PSP} during performance of routine rounds. The leaking pipe was downstream of SW valve SWN-38 {V} in the Primary Auxiliary Building (PAB) {NF}. Operations recorded the condition and initiated a condition report in the Indian Point 3 corrective action program (CR-IP3-2002-02038). Actions were initiated to perform non-destructive examination of the leaking pipe to characterize the extent of the pipe degradation. Radiographic testing (RT) was performed on June 6, 2002. Evaluation of the radiographs was not conclusive and recommended ultrasonic testing (UT) was performed on June 7, 2002.

Engineering evaluation of data collected concluded that the leaking pipe did not provide sufficient structural integrity for the piping to meet code allowables for pipe thinning and through wall leaks and therefore was inoperable. On June 7, Operations declared the designated SWS essential header with the leaking pipe inoperable and entered a Limiting Condition for Operation (LCO-2002-0241), for the SWS, Technical Specification (TS) 3.7.9.E.1, at approximately 2035 hours. At 2116 hours, Operations secured containment fan cooler units (FCU) {BK} 31, 32, and 35, closed applicable valves {V} to isolate the leaking section of pipe to facilitate repairs, and declared radiation monitors (RM) R11 and R12 {IL} inoperable. The action taken to isolate the degraded section of SW piping restored the safety function for all portions of the SWS except for three (3) FCUs supplied by the isolated section of SW piping. On June 8, at 2241 hours, the Protective Tag Out (PTO) for the degraded SW pipe was removed. On June 9, approximately 0040 hours, the FCUs were started and radiation monitors R11 and R12 declared operable to perform containment {NH} pressure relief. On June 9, at approximately 0158 hours, the radiation monitors (R11 and R12), and FCUs were secured and the SW pipe was tagged out (PTO) at 0245 hours. In accordance with TS 3.0.6, TS 5.5.14 and plant procedure OD-54, a safety function determination (SFD) was performed regarding the impact on the containment cooling system. The evaluation (SFD) concluded that the safety function of containment atmosphere cooling, pressure reduction and iodine removal were still met by the remaining equipment consisting of two (2) containment spray (CS) {BE} trains and two (2) containment FCU.

Entergy Nuclear Operations, Inc (ENO) determined on June 7, 2002, that repairs and SWS restoration could not be completed within the SW TS allotted 12 hour completion time. After consultation with the NRC on June 7 and 8, ENO prepared a request for enforcement discretion (NOED) to extend the SWS TS completion time 60 hours for a total duration of 72 hours. On June 8, at 0230 hours, operations was notified that the NRC granted an additional 60 hours to the TS 12 hour AOT for a total of 72 hours to complete repairs to the leaking pipe.

The leak occurred at the horizonally oriented butt weld on a vertical portion of a 18 inch diameter cement lined carbon steel SW supply header pipe (line number 408) to a tee connection. Visual inspection of the leak showed that it was in the weld toe area in the heat affected zone which had inadequate cement coverage at the weld gap. The weld associated with this leak was included in the Indian Point 3 Generic Letter 89-13 program but it had not been previously selected as an inspection sample.

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

After SW was declared inoperable on June 7, 2002, at 2035 hours, maintenance preparation activities began to repair the leaking pipe. On June 9, 2002, after post repair testing, operations declared the SWS Essential header operable and exited the SW TS LCO at 1657 hours, an inoperability duration of approximately 44.5 hours.

CAUSE OF EVENT

The cause of the condition was long term corrosion of the carbon steel weld metal at the unprotected gap remaining at the weld seam on a butt weld of the 18 inch diameter cement-lined carbon steel SW pipe (line number 408). The weld area corrosion was due to exposure of carbon steel to the brackish SW with oxygen. Exposure is due to inadequate cement lining at the pipe weld juncture. The pipe was cement lined piping installed during original construction with care not to burn through into the lining of the pipe during welding. This was done to protect the internal cement liner from damage that can be caused by the heat of welding. The resulting weld joints have a small gap between the ends of the cement liner on each side of the joint and may have isolated areas containing a slight crevice at the root of the weld. The slight gap permits river water (SW) to contact the bare metal of the weld which results in corrosion of the weld metal over time. The gap also permits water to seep under the cement liner causing the corrosion of the base metal. There is no documented evidence of a previous piping repair or replacement in this area and this is the first leak in this location. This weld appears to be unique, in that a similar tee weld on line 409 was found to be satisfactory based on a UT.

CORRECTIVE ACTIONS

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

- The affected SW piping (line number 408) was repaired in accordance with ASME Code Section XI requirements by removing the affected portion of the SWS from service, grinding out the degraded area, weld buildup as required to restore structural integrity and post repair verification testing. Repair and testing was completed June 9, 2002, and SWS declared operable at 1657 hours.

- The corrosion monitoring program that addresses Generic Letter 89-13 was assessed and appropriate adjustments made that will include radiographic testing of four additional weld locations of similar pipe size and flow characteristics prior to refueling outage 12 scheduled for March 2003.

- An extent of condition review was performed on SW piping that included a walkdown of the SW header that remained in service (line 409) and an inspection of a similar weld on this SW header (line number 409). On June 8, 2002, ultrasonic testing (UT) was performed on a weld in line 409 similar to the weld found to be leaking in line 408, which showed that the acceptance criteria for minimum required weld thickness was met. The walkdown verified that no leaks were evident. The review also included examination of prior inspections of this 18 inch diameter line (line number 409) that was examined by a boroscope. This previous inspection revealed no signs of missing cement liner or biological growth which can be a precursor to corrosion of the piping or weld metal. A review of the NDE for the leaking piping (line number 408) did not identify any new degradation mechanism that is not already considered by the SW corrosion monitoring program required by Generic Letter 89-13. Previous leaks on code class SW piping were found to be operable.

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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 the SW TS 3.7.9.E completion time of 12 hours was exceeded on June 8, 2002, at 0835 hours. On June 7, 2002, at 2035 hours, the SWS was declared inoperable and the TS action statement (AS) for TS 3.7.9.E with a 12 hour completion time was entered.

Enforcement discretion (NOED) was requested and 60 additional hours were verbally approved by the NRC on June 8, 2002, at approximately 0113 hours, prior to exceeding the existing 12 hours TS AOT. SW piping repair and post repair testing was completed on June 9, 2002, and the SWS declared operable at 1657 hours, a duration of approximately 44.5 hours.

A review of Licensee Event Reports (LER) for the previous two years did not identify any LERs due to TS prohibited conditions as a result of SW leaks that required repairs that exceeded the TS AOT. However, LER 1998-007 was identified as an event report due to a TS prohibited condition caused by a SW pipe leak which was structurally acceptable but did not meet ISI Class II.

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 or events requiring containment cooling or containment atmosphere pressure reduction while the SWS was inoperable and the three (3) FCUs were isolated from their SW supply. Normal containment atmosphere cooling during the repair time could be accommodated with the remaining two FCUs. SW remained available for remaining loads not isolated.

There were no significant potential safety consequences of this event under reasonable and credible alternative conditions. Engineering assessment of the degraded pipe under alternate conditions concluded the limiting pipe load was a design basis seismic event (DBE). The flawed area of the pipe that did not meet code requirements was determined to be conservatively enveloped by the through wall crack criteria of NRC Standard Review Plan Section 3.6.2, Branch Technical Position MEB 3-1 [section B.3.c(2)], for Moderate Energy piping. Engineering concluded that minimum SW flow could be provided for required SW loads under DBE conditions with the pipe flaw in line 408. A DBA and other transients would not provide pipe loads that would fail the pipe such that minimum SW flow would not be met. An alarm {IB} would have alerted operators to a potential SW leak (SW Header low pressure) and procedures were available [Alarm Response Procedure ARP-12 (Panel SJF-Cooling Water and Air), Off Normal Operating Procedure ONOP-RW-1 (SW Malfunction)] to direct operators to locate the leak and isolate the leaking pipe (close valve SWN-38) limiting potential flooding. The containment atmosphere cooling, pressure reduction and iodine removal function would be maintained since the remaining two (2) FCU and two (2) containment spray trains were operable to perform their function. Design basis assumptions regarding containment atmosphere cooling/pressure reduction and iodine removal are met by any of the following configurations: 1) two CS trains, 2) three fan cooler trains (i.e., 5 FCUs), or 3) one CS train and any two fan cooler trains (i.e., at least 3 FCUs). Both containment spray trains were unaffected by the leak repair. The design basis of the plant with respect to containment atmosphere cooling, pressure reduction and iodine removal was still met with two CS trains operable.

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A risk assessment of the isolated condition concluded that it was insignificant. Unavailability of a FCU does not impact overall core damage frequency (CDF) because the FCUs are not used to mitigate core damage. With respect to a radiological release from containment there is redundancy with the CS trains. The Large Early Release Frequency (LERF) is dominated by containment bypass scenarios (e.g.,steam generator tube rupture events and Loss-of-Coolant-Accidents outside containment) in which the FCUs do not provide an accident mitigating function. The baseline LERF value per the Indian Point 3 IPE is 5.8637 E-7 per year. The LERF value for the temporary configuration with the SW supply isolated to three FCUs is 5.868 E-7 per year. The increase of 5.0E-10 per year is a negligible change.

Compensatory action was taken to ensure that the extended TS AOT did not result in a net increase in radiological risk. Compensatory measures provided during the period of the NOED included 1) invoking the administrative control procedure (AP-19.1) for a special evolution to restrict work and protect the three emergency diesel generators (EDGs), offsite electrical feeders, the two operable FCUs, and two containment spray pumps from being taken out of service. The offsite electrical supply for Indian Point 3 includes four qualified feeders, all of which were available at the time of the special evolution. Only one feeder is required to meet design basis loading requirements and two feeders are required by TS to satisfy single failure criteria, 2) administrative controls designating a special evolution manager to provide extra management oversight and provisions to assure that certain redundant components are protected from being taken out of service, 3) performed a nondestructive examination (UT) of a similar weld on the uneffected SW header (line 409) which showed no leak and acceptance criteria was met, 4) performed a walkdown of the SW header that remained in service (line 409) and verified no leakage.