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February 15, 2001

Re: Indian Point Unit No. 2
Docket No. 50-247
LER 00-01-01
NL-01-018

US Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Station P1-137
Washington, DC 20555-0001

The attached Supplemental Licensee Event Report LER 00-01-01 is hereby submitted in accordance with the requirements of 10 CFR 50.73. This LER supplement identifies various corrective actions which have been implemented as a result of this event. The completion of certain system modifications and associated tests during plant heat up dictated the submittal date for this supplement.

Sincerely,
A. Alan Blind

Attachment

C: Mr. Hubert J. Miller
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NRC FORM 366 (6-1998)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 06/30/2001

LICENSEE EVENT REPORT (LER)

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

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TITLE (4)

Manual Reactor Trip Following Steam Generator Tube 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
2	15	2000	2000	-- 001 --	01	02	15	2001	FACILITY NAME	DOCKET NUMBER

OPERATING MODE (9)	N	POWER LEVEL (10)	99

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)	X	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)	X	50.73(a)(2)(iv)		OTHER
	20.2203(a)(2)(iii)		50.36(c)(1)	X	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)
John McCann, Manager, Nuclear Safety & Licensing	914 734-5074

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
X	AB	SG	W351	Y					

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 February 15, 2000 at 19:29, Eastern Standard Time (EST), with Indian Point Station, Unit 2 operating at 99 percent reactor power, operators manually shut down the unit and declared an Alert due to a primary to secondary leak in 24 steam generator. The emergency response organization was activated. Operators began cooling down and depressurizing the reactor coolant system as required by procedures. 24 steam generator was isolated at about 20:34. At about 21:00, the rate of the plant cooldown that was in progress was observed to increase. Pressurizer level could not be maintained greater than 9 percent, and at about 21:05, operators manually initiated safety injection. Pressure in the reactor coolant system and 24 steam generator was equalized by 22:50. However, later events caused reactor coolant water to flow into the steam generator secondary side. The cooldown continued, including a transition to the residual heat removal system, on February 16 at 12:40. The plant was brought to cold shutdown on February 16 at 16:57, and the Alert was terminated at 18:50. There was no detectable increase in normal background levels of radioactivity as measured by offsite environmental sampling and monitoring equipment.

As a result of the Alert, initial notifications to the State, local county authorities, and the NRC resident inspector were made on February 15 at 20:05. The NRC Operations Center was notified via the Emergency Notification System at 20:08. This report is being made pursuant to 10 CFR 50.73(a)(2)(I)(A) due to the completion of a plant shutdown required by Technical Specifications as a result of the declaration of the Alert classification.

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PLANT AND SYSTEM IDENTIFICATION:

Westinghouse 4-Loop Pressurized Water Reactor

EVENT IDENTIFICATION:

Manual Reactor Trip Following Steam Generator Tube Failure

EVENT DATE:

February 15, 2000

REFERENCES:

Condition Report (CR) Nos: 200000983, 200001026, 200001033, 200001012, 200001015, 200001024, 200001025, 200001034, 200001037, 200000984, 200001114

PAST SIMILAR EVENTS:

None

EVENT DESCRIPTION:

On February 15, 2000 at about 19:17, the R-61D Nitrogen-16 (N-16) leak detection monitor for 24 steam generator and R-45 the condenser air ejector discharge monitor at Indian Point Station, Unit 2 (IP2) alarmed, indicating primary plant (reactor coolant system) leakage into the steam system. Prior to this event, primary to secondary leakage was approximately 3.5 gpd. Leakage was being closely monitored. The R-49 steam generator blowdown monitor showed an upward trend. At about 19:19, the pressurizer level started to decrease. With alarms received from R-61D and 24 steam generator secondary system radiation monitor (R-55D), indications were that there was a substantial primary to secondary leak in 24 steam generator. Operators entered Abnormal Operating Instruction (AOI)-1.2, "Steam Generator Tube Leak." At 19:19 a second charging pump was started to maintain pressurizer level.

By 19:22, steam generator blowdown was isolated. At 19:29, the primary to secondary leakage was beyond the capacity of a single charging pump, and the reactor was manually tripped. An Alert was declared, and the emergency response organization was activated.

Operators entered Emergency Operating Procedure, E-0, "Reactor Trip or Safety Injection." With the exception of pressurizer level, plant post-trip conditions were as expected. There were no indications that a safety injection was required at this time.

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Operators transitioned to procedure ES-0.1, “Plant Trip Response” to continue plant recovery. At 19:40, auxiliary feed water was secured to 24 steam generator. Level in 24 steam generator began to stabilize at approximately 14 percent. The level in 24 steam generator began to decrease as its steaming rate exceeded the make up rate from the primary to secondary leak. Auxiliary feedwater was re-established to 24 steam generator at 20:10 and again secured at 20:24. At 20:18, isolation of 24 steam generator was initiated per AOI-1.2. At about this time, the setpoint for the atmospheric relief valve for 24 steam generator was adjusted from its normal setting of 1020 psig to the procedural recommended setting of 1030 psig. Pressure in 24 steam generator at this time was 950 psig. Charging pump suction was shifted to the Refueling Water Storage Tank (RWST) at 20:22 to provide a large source of borated inventory for the reactor coolant system. At 20:34, the MS-1-24 main steam isolation valve for 24 steam generator, was closed, completing isolation of 24 steam generator. The plant was stable and the operators were briefing on the cooldown procedure, POP 3.3, “Plant Cooldown.” Primary system boration was in progress.

At about 20:58, the pressure in 24 steam generator reached 1020 psig. At 20:59 this pressure peaked at 1023 psig and then turned downward. There was no indication of an opening of 24 steam generator atmospheric relief valve. The downward turn of 24 steam generator pressure is attributed to cooldown. Reactor coolant system temperature decreased 4 degrees during this period, caused by a combination of an increase in auxiliary feedwater to the intact steam generators and their steaming rates.

At 21:02, a larger steam flow condition commenced as a result of the opening of the condenser steam dump valves and blowing down 21, 22 and 23 steam generators. Steam flow increased until 21:03 at an average of about 320,000 lbm/hour per steam generator. The steam flow increased the cooldown rate of the primary system and a corresponding decrease in pressurizer level and pressure. At 21:13, the steam flow condition from 21, 22, and 23 steam generators stopped.

Since pressurizer level could not be maintained greater than 9 percent, a manual safety injection was initiated at about 21:05. Operators re-entered Emergency Operating Procedure E-0, “Reactor Trip or Safety Injection.” The continuing cooldown caused a rapid plant depressurization. Pressurizer level decreased as the pressure within the primary system decreased due to the cooldown.

Safety injection flow commenced at 21:07 when primary system pressure fell below the 1500 psi shutoff head of the high head safety injection pumps. At about 21:13, steam flow from 21, 22 and 23 steam generators stopped and operators transitioned into E-3, “Steam Generator Tube Rupture.” Safety injection flow stopped at 21:15 when the plant re-pressurized above 1500 psi. The plant cooldown and depressurization continued and safety injection flow resumed at 21:28 until the high head safety injection pumps were secured at about 21:36. Primary to secondary pressure difference in 24 steam generator was eliminated by about 22:50 and at about 22:52, operators transitioned to procedure ES-3.1, "Post Steam Generator Tube Rupture Recovery- Backfill." At this time the pressure difference across the break was approximately zero.

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The backfill recovery method slowly cooled the plant and maintained pressure control. This procedure maintained primary side plant pressure lower than 24 steam generator secondary side pressure, removed steam generator inventory to the primary system, and subsequently removed this inventory via the letdown system.

At 23:36 a cool down of the plant was begun per step 5 of ES-3.1 to bring the system into a cold shutdown condition. Cooldown was via the steam dumps to the main condenser. On February 16 at 00:05, this cooldown was terminated when condenser vacuum was lost. Vacuum was lost due to misoperation of the steam jet air ejectors (SJAE). The SJAE steam supply valve was in manual control. As steam pressure varied in the main header as the plant cooled down, the supply pressure to the SJAE changed as well. This steam supply pressure dropped below the point where the SJAE could efficiently remove non-condensible gases from the main condenser.

Plant cooldown was re-established at 00:05 using the atmospheric relief valves for 21, 22 and 23 steam generators. Cooldown continued with these valves until main condenser vacuum was re-established at 01:15. At that time, the atmospheric relief valves for steam generators 21, 22 and 23 were closed, and the cool down recommenced using the steam dumps to the condenser.

At 02:10, operators filled the Isolation Valve Seal Water System (IVSWS) seal water supply tank as part of their post safety injection recovery actions. The IVSWS is activated on a containment phase "A" isolation signal. This type of signal closes selected containment isolation valves in order to prevent contamination from leaving the containment following an accident. The IVSWS then provides pressurized water, from the seal water tank, to the space between the paired containment isolation valves. This ensures that any potential valve leakage would leak into the leakage source, and not result in a release. As designed, when the manual safety injection occurred at 21:04, this also caused a containment phase "A" isolation.

One of the valves sealed with IVSWS water is the Component Cooling Water System (CCW) thermal barrier return flow from the reactor coolant pumps. This system is not isolated on a phase "A" isolation signal, but rather, is isolated on a phase "B" containment isolation signal. During this event a phase "B" isolation signal was not generated, nor required. IVSWS seal water flowed into the open CCW containment isolation valve and from there into the CCW system. This condition necessitated periodic IVSWS tank refilling.

At 02:00, the primary plant temperature was 400 degrees F, and pressure was 700 psig. Cooldown and depressurization of the plant continued per ES-3.1.

At 07:16 the primary plant cooldown was stopped at approximately 304 degrees. During this period, 24 steam generator pressure continued to decrease as level continued to increase. From 05:30 through 06:16, condenser vacuum was degrading. Primary plant temperature control was again transferred to the intact steam generator atmospheric relief valves.

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At this time, a procedural question was raised regarding step 9 of ES-3.1. This step requires that the primary system pressure be less than 300 psig, and the temperature be less than 350 degrees F, before placing the Residual Heat Removal (RHR) system into service. RHR is the system normally used to bring the plant to cold shutdown and to maintain core cooling when in cold shutdown. Step 9 states that when these conditions were met, to place the RHR system in service per System Operating Procedure (SOP) 4.2.1 "Residual Heat Removal System."

SOP 4.2.1, step 2.5, requires primary system pressure to be less than or equal to 450 psig in order to place RHR into service. SOP 1.3 "Reactor Coolant Pump Startup and Shutdown" step 2.10, requires that the reactor coolant pumps be tripped if reactor coolant system pressure goes below 350 psig. In order to meet the more restrictive reactor coolant system pressure limits of ES-3.1 for RHR operation, the reactor coolant pumps would have to be tripped prior to placing the RHR system into service. Reactor coolant pump operation is required for normal pressure control of the reactor coolant system. Stopping the reactor coolant pumps would remove normal pressure control and require the use of auxiliary pressurizer spray via the charging pumps for pressure control. To comply with Technical Specifications, a reactor coolant pump was kept in operation. The operating crew in conjunction with operations management decided to halt the cooldown while a change to ES-3.1 was sought to allow for normal transition from steam generator cooling to RHR cooling. This procedural change was instituted in accordance with 10 CFR 50.54(x).

During this period, pressure in 24 steam generator continued to decrease and level continued to increase. Since no cooling was present, the decreasing pressure could only have been caused by leakage past the main steam isolation valve, MS-1-24. Post-event analysis of activity downstream of this valve confirmed that such valve leakage had occurred.

At 08:52, vacuum was restored to the main condensers, and primary plant temperature control was returned to the condenser steam dumps. Plant temperature was maintained at 305 degrees. At 09:19, the requested change to ES-3.1 was issued and the procedure changed to allow entry into RHR operation at a pressure higher than 300 psig, allowing continued reactor coolant pump operation during the transition. At this time, 24 steam generator pressure was 310 psig and decreasing. Reactor coolant system pressure was 388 psig and steady. 24 steam generator narrow range level was 86 percent and rising.

At 10:12, a crew was sent to the snubber supports for 24 steam generator main steam lines, upstream of the MS-24-1 stop valve, in order to isolate them physically. This was to prevent damage to the main steam line supports due to the weight of the water in the steam line should that line become water-filled due to the level increase in 24 steam generator. This process is called "pinning the steam lines." At 10:00, the level in 24 steam generator was increasing at approximately 2 percent per hour and was at 86 percent.

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At 10:32, 21 RHR pump was started to sample the RHR system for boron concentration and to commence warmup of the RHR system prior to placing it into service. At 12:34, the RHR system was placed in service. At 12:47, 24 reactor coolant pump was stopped. This was the last reactor coolant pump operating. Plant cooldown on RHR cooling commenced at 13:10. Initially when the pressurizer auxiliary spray valves were opened, reactor coolant system pressure control was not effective. Spray water was not entering the pressurizer because the normal spray valves were not closed. When the normal spray valves were closed, reactor coolant system pressure was maintained by the auxiliary spray system and charging pumps.

RHR cooling continued normally until at 16:56, at which point the reactor coolant system temperature decreased below 200 degrees and the plant entered cold shutdown. This condition satisfied the final requirement of procedure ES-3.1, and operators transitioned to their normal cold shutdown operating procedures. The Alert was terminated on February 16, 2000 at 18:50.

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EVENT ANALYSIS:

Pre-Event Leakage

On October 14, 1999, the plant was returned to service following a 45 day outage. A primary to secondary leak rate was calculated daily, based upon the comparison of the noble gas activity (Xenon-133) in the condenser air ejector (CAE) discharge to that in the reactor coolant system. The daily leak rate was calculated at about 2 gpd until January 31, 2000, when a slight increase to about 2.7 gpd was observed. The leak rate fluctuated between 2.1 gpd and 2.7 gpd over the next several days. This slight leak rate increase was discussed at the morning plant status meeting. After February 10, the leak rate trend showed another slight increase to 3.5 gpd. The leak rate on February 15 was 3.1 gpd. R-61D monitor readings, which are logged by the Watch Chemist once a shift, also indicated a slight increase in the leak rate between February 3 and February 15. The Watch Chemist log shows that the N-16 leak rate for 24 steam generator was 3.4 gpd at 19:15 on February 15.

Post-Event Leakage

The flow rate through the failed tube varied throughout the event. The highest flow rate was encountered prior to the reactor trip, and was approximately 109 gpm. After the reactor trip and prior to the manual safety injection, the primary to secondary side pressure differential decreased and the flow rate decreased to an estimated 91 gpm. Between safety injection and cold shutdown the estimated flow rate varied between 70 gpm and 0 gpm.

The estimated volume of water transferred from the primary side to the secondary side is summarized as follows:

Tube Failure to Reactor Trip	1313 gallons
Reactor Trip to Manual SI	8685 gallons
Manual SI to Cold Shutdown	9199 gallons

The total volume of primary side water transferred to the secondary side is estimated at 19197 gallons.

Operator Response

The overall operator response was successful in mitigating the effects of the tube failure. The cooldown rate of the reactor coolant system was greater than expected when the steam dumps were placed in service. Additionally, a procedural inconsistency between ES-3.1 and SOP 4.2.1 regarding the entry conditions for RHR was discovered during the event increasing the time required to reach cold shutdown. This necessitated a procedural change, which was instituted in accordance with 10 CFR 50.54(x). Additional issues included communication problems with the Technical Support Center (TSC), conflicting boron concentration values at turnover, conflicting procedural requirements regarding reactor coolant system pressure limitations prior to RHR switchover, insufficient guidance for closure of the CCW valves 822A and 822B, and the performance of PT-V14 to enter Overpressure Protection System (OPS). As a result, the time required to proceed to cold shutdown was longer than expected.

Radiological Releases

No releases in excess of Technical Specification limits to unrestricted areas occurred. There was no detectable increase in normal background levels of radioactivity as measured by offsite environmental sampling and monitoring equipment. All potential radioactive gaseous and liquid effluent release paths have been evaluated in a bounding release calculation.

This bounding calculation considered potential releases from the condenser air ejector, the atmospheric relief valves, the Steam Generator Blowdown Flash Tank, and from the gland seal exhaust. The calculated maximum whole body total dose at the site boundary for the Alert period, resulting from all potential releases, was a small fraction of the permissible annual dose. The calculated maximum organ total dose was a small fraction of the permissible annual dose.

Contamination Control

Proper radiological controls were established in conventional plant areas following this event. Personnel entering conventional plant areas after the event were either accompanied by a health physics technician who surveyed the area and established radiological controls, or an evaluation of the work to be performed determined that there were no radiological consequences of the work. As a result, there was no personnel contamination or unidentified area contamination associated with the event.

Personnel Radiation Exposure

The need to drain the secondary side of 24 Steam Generator to the waste processing system was recognized during the event, and plans were developed for the establishment of proper radiological controls. As a result, there were no radiation exposure problems associated with this process.

Radiation Monitoring

All plant effluent or process radiation monitors responded properly to the increased activity as a result of the primary to secondary leak in 24 steam generator. The affected monitors were R-61D, N-16 leak monitor for 24 steam generator; R-45, condenser air ejector discharge monitor; R-49, steam generator blowdown monitor; and R-55D, 24 steam generator secondary system monitor. Upon detection of the increased activity, R-45 alarmed and automatically diverted to the containment. R-61D functioned as expected; however, its recorder was unavailable due to mechanical problems. R-61D data was being recorded manually. Prior to the event, the automatic isolation function of R-49 was in bypass for testing. Its alarm function was available. In accordance with AOI-1.2, operators manually isolated steam generator blowdown at 19:22, approximately 5 minutes into the event.

Technical Specifications

A post-event review of Technical Specifications was performed to determine all of the Technical Specification Limiting Conditions for Operations (LCO) which were affected during this event. In accordance with NUREG 1022, Revision 1 guidance regarding multiple failures and related events, these events are being reported herein. The following are those Technical Specification LCOs, which were entered during the Alert:

TS 3.1.F.2.a.(1) for steam generator primary to secondary leakage in excess of 0.3 gpm. Entered and exited on February 15 at 19:30, and February 16 at 16:57, respectively.

TS Table 3.9-1 for R-49 steam generator blowdown monitor, in test prior to event. Entered on February 15 at 14:20.

TS 3.3.H.2 for control room air filtration system inoperable prior to event. Entered on February 15 at 6:20.

TS 3.0.1 for placing vapor containment sump 29 and 210 in "off" due to Phase A containment isolation. Entered and exited on February 15 at 22:34, and February 16 at 6:30, respectively.

TS 3.1.F.b.(6) for R-41 and R-42 containment atmosphere particulate and gaseous radioactivity monitors isolated during Phase A containment isolation. Entered and exited on February 15 at 22:34, and February 16 at 6:30, respectively.

TS 3.9.B.2.c for R-50 large gas decay tank monitor tripped due to high pressure. Discovered on February 16 at 14:39, and monitor returned to service on February 17 at 10:00.

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TS 3.0.1 for IVSWS tank water loss. Entered and exited on February 16 at 2:10, and February 16 at 9:05, respectively.

TS 3.1.B.1 for reactor coolant system heatup and cooldown not to exceed 100 degrees F/hour. The actual cooldown rate achieved was 103 degrees F/hour.

TS 3.1.B-5 for pressurizer heatup or cooldown rates averaged over 1 hour not to exceed 100 degrees/hour and 200 degrees/hour, respectively. Spray shall not be used if the temperature difference between the pressurizer and the spray fluid is greater than 320 degrees F.

Emergency Response

The Alert declaration resulted in the initiation of staffing of the Indian Point emergency response facilities which included the Emergency Operations Facility, Technical Support Center, Operation Support Center and the Joint News Center. Communications were established with state and county agencies, local officials and the NRC within required time guidelines. Emergency response facilities were manned and activated on February 15. The TSC was declared activated at 20:59. The OSC and EOF were declared activated at 21:15. Site accountability was formally completed at 21:47. Courtesy notifications of local officials were not all completed in a timely manner.

The Emergency Plan adequately protected the health and safety of the public in this event, but the Emergency Response Organization performance did not meet all expectations. In almost all cases these weaknesses had been previously identified by the Emergency Preparedness Department. Several equipment malfunctions were experienced over the duration of the emergency response including: failure of the Emergency Response Data System for the first few hours of the event due to a telephone line failure, and improper operation of the data communication link from the fixed offsite radiation monitor data collection system. Field monitoring teams were dispatched offsite to monitor for any potential radiological release.

RCS Heatup and Cooldown Rates

A post-event review of primary system plant data to determine whether any Technical Specification requirements associated with the heatup and cooldown rates of the reactor coolant system were exceeded was performed. During the event, the reactor coolant system temperature cooldown exceeded 100 degrees F per hour on all four loops by 3 degrees. Also, the differential temperature between the pressurizer and the spray flow may have exceeded 320 degrees F by approximately 2 degrees F. Subsequent evaluations of the affected components have determined that the post-event cooldown did not adversely affect the structural integrity of the fuel or any of the primary components.

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Event Review

In accordance with Station Administrative Order 112, "Corrective Action Program," a root cause review team was formed to determine the cause of the event, "lessons learned," actions to correct plant conditions, and the "extent of condition." The focus of this review was the way in which personnel and systems responded to the event. On March 30, 2000 a final report documenting the results of the event investigation team was issued. This report summarizes root causes and corrective actions for the deficiencies noted by the event investigation team.

Concurrently, a NRC Augmented Inspection Team (AIT) was dispatched to the site on February 18, 2000. This team conducted an inspection to determine the specific causes, safety implications, and associated licensee actions in response to the steam generator tube failure. The AIT inspection results were documented in NRC Inspection Report No. 05000247/2000-002. Subsequent follow-up inspections in the areas of Emergency Preparedness, and corrective actions were conducted by the NRC. The results from these activities were documented in NRC Inspection Report Nos. 05000247/2000-006 and 05000247/2000-007.

EVENT SAFETY SIGNIFICANCE:

SGTR Accident Analysis

Evaluation of this event demonstrates that the consequences of the steam generator tube failure event on February 15, 2000 were bounded by the analysis presented in the UFSAR. Both the tube leak size and time to achieve isolation of steam blowdown were within the analyzed accident assumptions. In terms of public health consequences, the event had no effect. Core thermal and shutdown margins were met and fuel integrity was not compromised.

CORRECTIVE ACTION:

The following is a summary of the major corrective actions which have been implemented as a result of this event. Because of the complexity and evolving nature of our assessments, new actions and/or revisions to completed actions may occur.

Steam Generator Inspection and Replacement

A 100 percent inspection of the tubes in all four steam generators was performed. The location of the tube leak in 24 steam generator was identified at Row 2, Column 5 near the top, outer radius of the U-bend. The cause of the tube failure was attributed to primary water stress corrosion cracking (PWSCC). The results of these inspections are discussed in the "2000 Refueling Outage Steam Generator Inspection Condition Monitoring and Operational Assessment" reports, which were provided to the NRC staff on June 2, 2000. Subsequent to the completion of these inspection activities a project to replace the original steam generators was begun. This project was completed at the end of 2000.

IVSWS Design Improvement

To prevent unnecessary inventory loss from the IVSWS seal water supply tank following a phase "A" containment isolation signal, enhancements were made to the IVSWS to improve system response. Flow orifices were installed on the IVSWS lines which receive a phase "B" signal, and solenoid valves were installed to control flow.

Steam Jet Air Ejector (SJAE) Control Upgrade

During the post-event cooldown phase, misoperation of the SJAE necessitated using the atmospheric relief valves. The unavailability of PCV-1222 required that the steam supply to the SJAE be maintained in manual control. A modification to revise the valve's controls was completed prior to plant restart.

Condenser High Pressure Steam Dump Improvement

The high pressure condenser steam dump system did not respond as expected during this event. The higher than desired cooldown of the reactor coolant system has been attributed to the operating characteristics of the existing steam dump header pressure controller. A modification to replace the existing current to pneumatic (I/P) converter with an improved model will improve the control and response of the high pressure steam dump valve. This modification was completed prior to plant restart.

Operating Procedure Revisions

ES-3.1, "Post Steam Generator Tube Rupture Recovery - Backfill"

Prior to placing the Residual Heat Removal (RHR) system into service, a procedural question was raised regarding step 9 of procedure ES-3.1, "Post Steam Generator Tube Rupture Recovery - Backfill." As discussed in the EVENT DESCRIPTION, a procedural discrepancy between ES-3.1 and SOP 1.3 relative to RHR system operating pressure limitations and reactor coolant pump shutdown pressure necessitated revisions to be made in accordance with 10 CFR 50.54(x). Based upon further analysis, the RHR system pressure limit was increased from 300 psig to 370 psig. ES-3.1, step 9 was revised to permit placing the RHR system into service with primary system pressure less than 370 psig. SOP 4.2.1, step 4.1.2.(2) was similarly revised to reflect this change.

SOP 1.3, "Reactor Coolant Pump Startup and Shutdown"

The primary coolant system pressure limit for reactor coolant pump shutdown was reduced from 350 psig to 300 psig. SOP 1.3, step 2.11 was revised to require RCP shutdown if RCS pressure decreases to less than 300 psig.

SOP 1.4, "Pressurizer Pressure Control"

Initially when the pressurizer auxiliary spray valves were opened, the operating crew observed that reactor coolant system pressure did not respond as expected. The cause of this occurrence was attributed to the normal spray valves not being closed, thus allowing spray water to bypass the pressurizer. Only upon the closure of the normal spray valves was reactor coolant system pressure control established. To correct this procedural deficiency, additional guidance was provided in System Operating Procedure SOP 1.4, to instruct the operator to close the normal spray valves PCV-455A and B when switching to auxiliary spray.

Emergency Preparedness

During this event various weaknesses relative to the emergency preparedness program resulted in delayed augmentation of the Emergency Response Organization and accountability of onsite radiation emergency workers. Additional equipment deficiencies affected the dissemination of factual and consistent information to the public. Following this event, an independent review team consisting of emergency response specialists from other utilities was appointed to assess the adequacy of the Emergency Response Organization's performance. Concurrently, the NRC Augmented Inspection Team (AIT) evaluated the performance of the Emergency Response Organization. The inspection team's findings were provided in Inspection Report 05000247/2000-006. Specific actions have been identified to correct the Emergency Response Organization weaknesses which occurred during this event. Corrective actions were provided by Con Edison to the NRC in a letter dated September 8, 2000.