NRC FORM 366 (5-92) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
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TITLE (4)
Mis-Positioning of Division B Drywell Spray Block Valve

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER 05000
10	12	95	95	007	00	11	13	95	FACILITY NAME	DOCKET NUMBER 05000

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)							
			20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
POWER LEVEL (10)	100 %		20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER
			20.405(a)(1)(iii)	✓	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		(Specify in Abstract below and in Text, NRC Form 366A)
			20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
Tom Parker	612-295-1014

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

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)
NCR FORM 366 (5-91)

A drywell spray manual block valve was found in the incorrect position during power operations. It is believed to have been in the wrong position since the last refueling outage 12 months ago. The error was discovered by operations personnel. All Emergency Core Cooling Systems valves outside the inerted containment were re-verified to be in the correct position. No other valving errors were identified during this verification.

This error was caused by operator error, although the specific operator errors could not be identified.

This event has been discussed with shift personnel. Formal training will be provided to all personnel involved in valve line-ups. The valve line-up process, the independent verification process, the locked valve process, and the hold and secure card process will be evaluated for possible improvements. The refueling outage process will be reviewed for possible safety enhacements.

Description

While at 100% power on October 12, 1995, valve RHR 74-2 was found closed and unlocked with a Hold card from the 1994 outage attached to it. RHR 74-2 is the manual Division "B" drywell spray block valve in the Residual Heat Removal (RHR)(EIIS System Code:BO) system. It is required to be locked open at power. This error was discovered during on-line maintenance activities on the RHR system.

RHR 74-2 is located outside the drywell between the RHR Drywell Spray motor operated valves and the spray header inside the drywell (See Figure 1). RHR 74-2 is in the reactor water cleanup pump area, near the reactor water cleanup line which makes the area a high radiation area. The valve is a 10" rising stem valve, with no remote indication. Its closure blocks one of two paths for drywell spray to be injected into the drywell atmosphere.

On-line maintenance was being performed on the "B" RHR train. On October 11th, 1995 an operator hung a Hold card, card number 7 of isolation 95-01353, on RHR 74-2. The operator reported to the Control Room that RHR 74-2 was found closed with another tag on it. This was not reported to shift management. The control room staff was aware of additional isolations being hung associated with the current maintenance activities and did not consider this additional card to be abnormal.

At 1042 on the 12th of October 1995, card number 7 on isolation 95-01353 was removed. Again, the additional card was noticed. An investigation identified that the card was associated with a work order performed (and improperly closed out) during the 1994 refueling outage. The existing card was cleared and the valve opened. It is believed that the valve has been shut since the startup associated with the last refueling outage in October of 1994.

Upon discovery of this mispositioning, a one hour report to the NRC was initiated and the NRC Resident Inspector notified. All locked valves outside the inerted drywell were verified to be locked and in the proper position. All critical locked valves inside the drywell were determined to be in the proper position by indication or by correct system operation to date. All Emergency Core Cooling system valves outside the inerted drywell were verified to be in the proper position. All on-line maintenance has been temporarily halted unless specifically authorized by the plant manager.

Cause

RHR 74-2 was mis-positioned as a result of personnel errors. An investigation team has interviewed all personnel involved, and has done an extensive review of all associated documents, logs, procedures and work packages. The results have been reviewed by a working level committee, a management oversight committee and the quality services group. Other associated events have been reviewed for applicability. The investigation has not identified the exact cause of the event; however, a most probable scenario has been determined and is discussed below.

Three processes were involved: the valve line-up process, the hold and secure card process and the locked valve process.

Valve Line-up Process

At the end of the 1994 refueling outage, two licensed individuals signed off on the master copy of the RHR Prestart Checklist that valve RHR 74-2 was open and locked. Since the valve is believed to have been in the wrong position during startup, the purpose of this process was not fulfilled. The process is believed to be sound, as it has been used successfully for approximately 10 years, but errors occurred in implementing the process.

One possibility, which was ruled out, was that the personnel falsified the checklist. This was ruled out following personnel interviews and the review of the plant ALNOR[1] records. RHR 74-2 is approximately 3 to 5 feet below the reactor water cleanup line which reads 3,000 mr/hr on contact. Anyone observing the position of this valve will be exposed to a 100 to 600 mr/hr field. The ALNOR records the maximum dose rate to which the individual is exposed. The independent verifier logged into the reactor water cleanup pump room on Radiation Work Permit 22 (RWP-22) for a 20-minute period and that person's ALNOR recorded a dose rate of 589 mr/hr. The ALNOR data is not as definitive for the first operator to check the valve who was exposed to a 237 mr/hr field during an 8-hour time period. This individual did not log into RWP-22. Plant

[1] ALNOR is a personal electronic dosimeter.

procedures do not require personnel to log into every high radiation area if they expect to receive less than 10 mr per entry. Operators entering several high radiation areas, but accumulating only a small dose in each, are required only to log into the area where they would receive the highest dose. The records are not inconsistent with the individual being in the vicinity of RHR 74-2. The higher dose rates for the two individuals were on different days, suggesting independent verification was performed. No other valve mis-positionings occurred on systems lined up by the two individuals who lined up RHR 74-2.

Another possibility was that the valve was repositioned open before the checklist was completed and closed after the valve checklist was completed. An exhaustive search could not find any procedure, work document or temporay isolation that could support any changes in valve position during the verification.

The personnel erred in either 1) "seeing" the valve in the correct position when it may have been in the incorrect position, or 2) identifying the valve in the closed position on the working copy of the valve line-up checklist and this information was incorrectly transferred to the master checklist line-up copy. Both of these errors are unlikely, but a more probable scenario could not be developed.

RHR 74-2 is a 10" rising stem valve. Hold cards are approximately 4" by 7", bright, red, plastic cards. It is unlikely that two individuals in the vicinity of RHR 74-2, with:

> A hold card on the valve handwheel,
> The 10" valve stem not visible above the handwheel
> and
> The chain and lock not locking the valve,

could "see" this valve as locked open.

The other possible error involves transferring initials from the working copy of the prestart checklist to the master copy. The operators use one copy, the working copy, to take with them as the valve checklist is performed. Once completed, signatures are transferred to the master copy. In this case, a shift manager transferred the first operator's initials to the master copy and the

independent verifier transferred their own initials. Both sets of initials would need to have been transferred in error.

The most likely scenario is that the first operator observed that the valve was closed and so noted on the working copy of the valve checklist. The independent verifier, seeing the note, also observed the valve to be in the incorrect closed position. Since the independent verifier expected to see the valve closed, its incorrect position did not make a significant mental impression. An error could have been made by a shift manager in transcribing the first operator's initials, so that the master checklist incorrectly indicated the valve was locked open. The independent verifier could then have relied on the transferred signatures of the first operator on the master copy and incorrectly initialed that the valve was open on the master copy when transferring their initials. These errors are not consistent with management expectations.

Hold Card Process

The hold card placed on the valve during the outage was not removed when the work package was closed out by the shift manager. All cards should be cleared before the work package is closed out.

There were two conflicting documents available to the shift manager when processing the work package: 1) the hold card isolation paperwork indicated the valve to be closed with a card on it, and 2) the more recent valve line-up information indicated the valve to be locked open (and presumably uncarded). It is postulated that the shift manager assumed the more recent valve line-up information to be correct, and closed out the work package without sending anyone to the valve to resolve the discrepant documents. This is not in accordance with management expectations and approved procedures. The shift manager that closed out the work order does not remember their thinking behind the closure of this work order. There were several hundred work orders closed out during the last several days of the outage. However, the shift manager agrees that this theory is possible.

A large number of work orders are closed out by the shift supervisor's office during the last several days of a refueling outage. The sorting, grouping, testing

and final closeout of this large number of work orders presents a significant challenge to the shift management. This could be be a contributing cause to this error.

Locked Valve Process

Following a refueling outage, the locked valve process uses the valve line-up process to determine valve position. Thus, it is dependent upon the valve line-up information being correct. The locked valves are checked quarterly. RHR 74-2 was exempted from this check, since it is in a high radiation area. Thus, its mis-positioning was not identified during subsequent quarterly checks.

The high radiation exemption for this valve was made during a period in plant history when the reactor water cleanup line was several times more radioactive. Subsequently, the line was replaced and currently reads approximately 3,000 mr/hr. Operations personnel also enter this area to drain water between the two drywell spray motor-operated valves following quarterly Inservice Testing. Considering these two facts, it is no longer appropriate to exempt RHR 74-2 from quarterly verification. Had RHR 74-2 not been exempted, the mis-positioning would have been identified during the performance of the first quarterly locked valve alignment check following the outage, in January 1995.

Analysis

Analysis of Reportability

Technical Specification 3.5.C requires that both containment spray/cooling subsystems shall be operable whenever irradiated fuel is in the reactor vessel and reactor water temperature is greater than 212°F. Each containment spray/cooling subsystem consists of the following equipment:

2 RHR Service Water Pumps
1 RHR Heat Exchanger
2 RHR Pumps
Valves and piping necessary for:
    Torus Cooling

Drywell Spray

The closure of RHR 74-2 made the drywell spray subsystem on the "B" Division inoperable. Section 3.5.C.4 allows one subsystem to be inoperable for 7 days. If the 7 days are exceeded, the reactor must be shut down within 24 hours in accordance with Section 3.5.C.5. The closure for approximately one year during power operation violates Section 3.5.C.

During the period when RHR 74-2 was closed, every time the Division "A" Emergency Diesel Generator was removed from service, a reactor shutdown was required within 24 hours. Technical Specifications allow the equipment supplied by an Emergency Diesel Generator to be considered operable when that Emergency Diesel Generator is inoperable, provided the redundant equipment is operable. In this case, the Division "B" drywell spray system was not operable because RHR 74-2 was closed. The Division "A" Emergency Diesel Generator was removed from service 15 times during the time that RHR 74-2 was closed; 11 of these were associated with required monthly surveillance testing. None of these periods of removal from service exceeded 24 hours.

During the Division "A" on-line maintenance, both RHR pumps were removed from service for 56 hours, during which the Division "A" drywell spray line was removed from service for 5 hours. The RHR divisions are cross-tied between the pump discharges and the drywell spray lines (Figure 1). Thus, loss of both "A" Division RHR pumps would not inhibit drywell spray. The "B" Division RHR pumps would have supplied the "A" Division drywell spray line. However, the plant Technical Specifications specify that the removal from service of the Division "A" RHR pumps with the Division "B" drywell spray block valve unknowingly closed, also violates Section 3.5.C.5.

This report is being made in accordance with 10 CFR Part 50, Section 50.73 since the Technical Specifications were violated (50.73(a)(2)(i)(B)).

Safety Significance

After reviewing the plant design bases for drywell spray, it has been determined that this event had no impact on the health and safety of the public. Had procedures required the use of drywell sprays, operations personnel had time and opportunity to

unisolate one of the two drywell spray headers. Even without operators unisolating one of the drywell spray loops, analysis shows that the drywell sprays are not needed to ensure the health and saftey of the public.

The plant design basis takes credit for the drywell sprays for one analysis of one accident situation and no transients. Following a Small Break Accident (SBA), drywell sprays are assumed to terminate hydrodynamic chugging loads on the Primary Containment Vent System. No drywell spray is necessary for larger breaks, as the torus quenchs the steam released to the drywell.

Chugging loads are the cyclic stresses caused by condensation of steam at the downcomer openings of the drywell vents. When a steam bubble collapses at the exit of the downcomers, the rush of water drawn into the downcomers to fill the void induces stress at the junction of the downcomers and the vent header (See Figure 2). Repeated application of such stresses could cause fatigue failure of the joints, thereby creating a direct path between the drywell and the torus airspace. Use of the drywell sprays in accordance with the Emergency Operating Procedures limits the fatigue stress cycles to ensure that no vent header failures occur.

The Emergency Operating Procedures require the operator to initiate drywell sprays at 12 psig in the drywell. Had a small break accident occurred during the time when Division "B" drywell spray was manually blocked and Division "A" was available, drywell spray would have performed its function ensuring the vent header remained intact. Had the accident occurred during the five hours when both drywell sprays were isolated, the operator would have had several indications that there was no drywell spray. The flow indicator would identify no flow[2] and an annunciator would alarm "CONTAINMENT SPRAY FLOW LOW." With no flow in the Division "B" drywell spray line, there are only three possible obstructions to flow: two motor-operated valves and the manual block valve. The valves are located near each other and in an area that would have been habitable following a small break accident. Operators would have quickly identified the mis-positioned valve or unisolated the Division "A" drywell spray line and drywell spray would have then been made available.

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[2] This flow indicator indicates the total divisional flow to both the drywell sprays and to torus cooling. However, the EOPs direct the operator to secure torus cooling prior to initiating drywell spray.

No failures of suppression pool (torus) structures would have occurred during the limited time when both divisions of drywell spray were isolated, even if the drywell sprays were not restored. For a small break accident, the Mark I analysis predicts that chugging loads start 300 seconds following the initiation of the event (See Figure 3, Case #1). At 600 seconds (10 minutes) following the initiation of the event, reactor depressurization is assumed to be manually initiated. Chugging loads are assumed to be terminated at 1200 seconds. Since the completion of the Mark I evaluations, the Emergency Procedure Guidelines were changed such that chugging loads are terminated by the initiation of drywell sprays. Monticello's Emergency Operating Procedures would have drywell sprays initiated at 12 psig, which would occur approximately 220 seconds following the initiation of the small break accident (See Figure 3,Case #2). With the drywell sprays initiated at 220 seconds, chugging loads would be eliminated and the Mark I analysis is conservative. If a small break accident would have occurred when both subsystems of the drywell sprays were inoperable, the Emergency Operating Procedures would have directed the operators to depressurize the reactor at 27 psig in the drywell (See Figure 3, Case #3). This is identical to the action assumed in the Mark I analysis, but it would occur at a later time than assumed in the Mark I analysis. The primary containment response to a small break accident indicates that 27 psig would be reached at approximately 1000 seconds following the initiation of the event. Reactor depressurization would have been initiated 400 seconds later (1000 - 600 = 400 sec). The additional 400 seconds of chugging loads have been analyzed and the limiting fatigue usage factor has been determined to meet code requirements. Thus, without drywell sprays no fatigue failure would occur.

If it is assumed, that drywell spray is not restored and the limiting fatigue location fails (even though the conservative fatigue analysis has considerable margin), no containment failure would occur due to the failure of the vent header. The joint between the downcomer and the vent header is the limiting fatigue location. Following failure of one downcomer joint, chugging would stop as the driving pressure would be equalized. No additional failures would occur. The Monticello Individual Plant Examination (IPE)[3] evaluated the effect of all eight vacuum breakers being open during loss of coolant accidents and found that for primary system breaks less than 14" in diameter, no containment failures resulted from the direct path between the torus and

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[3] Submitted to the NRC by letter dated February 27, 1992, from T. M. Parker to US NRC titled, "Submittal of Individual Plant Examination (IPE) Report."

drywell air space. Small break accidents are a subset of breaks less than 14" in diameter. The cross sectional area of eight vacuum breakers is greater than four times the cross sectional area of one downcomer. Therefore, we can conclude that if a downcomer joint had failed, it would have had no effect on the health and safety of the public.

Based on the above facts, there were no consequences to the health and safety of the public or the safety operation of the plant associated with mis-positioning of RHR 74-2.

Corrective Actions

These corrective actions will address all possible causes of this event.

1. The hold card was removed from RHR 74-2 on October 12, 1995, and the valve was opened and locked in the open position.

2. All locked valves outside the inerted drywell have been verified to be locked in their proper position.

3. All ECCS valves outside the inerted drywell have been verified to be in their proper position.

4. All critical locked valves inside the drywell were determined to be in the proper position by indication or by correct system operation to date.

5. All on-line maintenance has been temporarily halted unless specifically authorized by the plant manager.

6. The locked valve checklist will be changed to remove the high radiation exemption for RHR 74-2 as well as other RHR valves in its vicinity.

7. Management has addressed the improper closeout of the isolation associated with the hold card found on RHR 74-2 with the entire operations management staff. The following issues were addressed:

   - operations should have a questioning attitude

- follow the procedural processes
- self-checking

8. Training will be provided to all personnel involved in the valve line-up process on:
   - this event,
   - the importance of proper valve position,
   - the purpose of having locked valves, and
   - and the importance of independent verification.

9. The following processes will be evaluated for possible improvements:
   - valve line-up (checklists) process (including signature transfers),
   - independent verification process,
   - locked valve process, and
   - hold and secure card process

10. The process of conducting refueling outages will be evaluated for possible improvements in the areas of operations work load near the end of the outage. In addition, an evaluation will be performed on the integration of system restorations into outage activities.

<u>Failed Component Identification</u> - None
<u>Previous Similar Events</u> - None

FIGURE 1 - SIMPLIFIED RHR SYSTEM SHOWING AS FOUND CONDITION

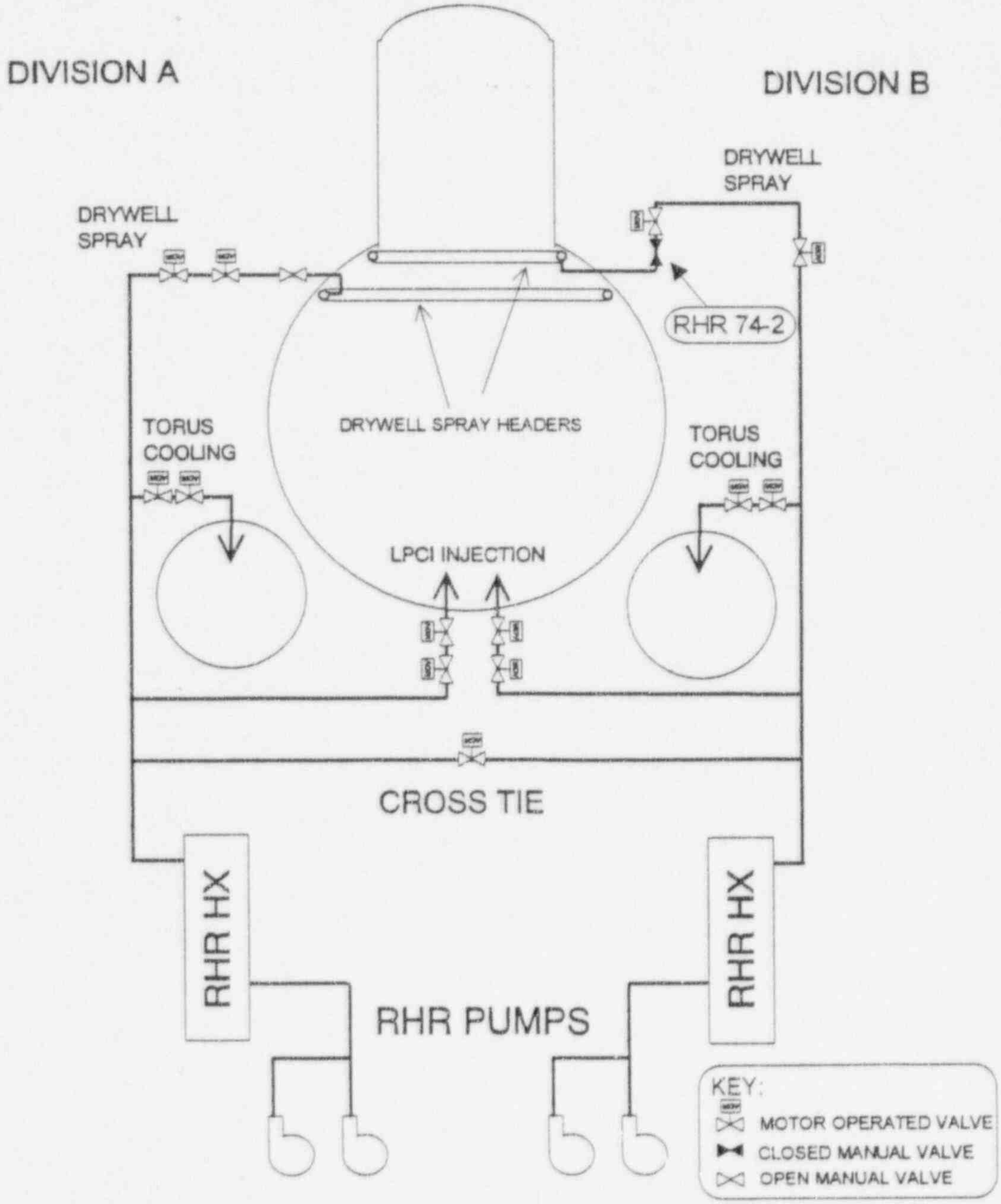
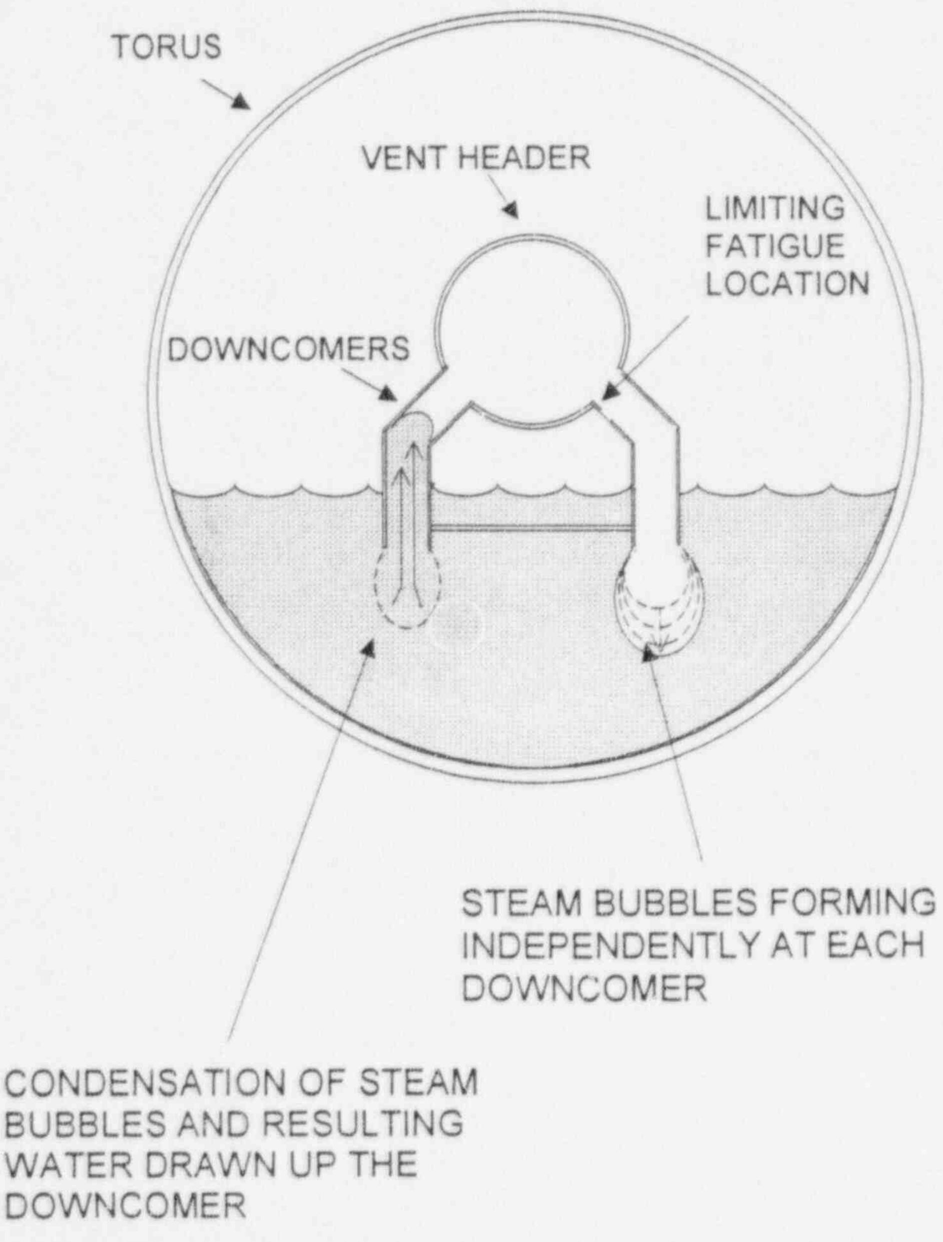


FIGURE 2 - CHUGGING IN THE TORUS



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

FIGURE 3 - VENT SYSTEM CHUGGING