7590-01-P

U.S. NUCLEAR REGULATORY COMMISSION

DOCKET NOS. 50-245, 50-336, AND 50-423

NORTHEAST UTILITIES

MILLSTONE NUCLEAR POWER STATION, UNITS 1, 2, AND 3

DOCKET NO. 50-213

CONNECTICUT YANKEE ATOMIC POWER COMPANY

HADDAM NECK PLANT

RECEIPT OF PETITION FOR DIRECTOR'S DECISION UNDER 10 CFR 2.206

Notice is hereby given that on November 25, 1996, as amended on December 23, 1996, the Citizens Awareness Network (CAN) and the Nuclear Information and Resource Service (NIRS) (Petitioners) submitted a Petition pursuant to 10 CFR 2.206 requesting certain actions associated with the Haddam Neck plant, which the Petitioners refer to as Connecticut Yankee, and the three Millstone units operated by Northeast Utilities (NU).

Petitioners allege that NU has, over the past decade, mismanaged its nuclear facilities in Connecticut and operated them in flagrant disregard of NRC regulations; that NU has failed to fulfill its commitments to the NRC; that NU management had concrete particularized knowledge of serious on-going violations of NRC regulations culminating in material misrepresentations to the NRC; that regulatory oversight by the NRC to assure NU's compliance with NRC regulations has been a blatant and abject failure; that NU is in violation of 10 CFR Part 50, Appendix B; and that these failures have culminated in inconsistent and inaccurate updated Final Safety Analysis Reports at NU's

nuclear facilities in Connecticut, thereby posing a significant safety concern for either continued operation of the plants or decommissioning.

The bases for these assertions are NU and NRC inspection findings and NU documents referred to in the Petition, the amendment and a VHS videotape, Exhibit A, which accompanied the Petition. The videotape has been transcribed and placed in the Commission's Public Document Room and local public document rooms. Areas identified are surveillance testing, operation outside the design basis, and degraded material condition. Petitioners assert that this information demonstrates that there are inadequate quality assurance programs at NU's nuclear facilities in Connecticut, that NU has made material false statements regarding its Millstone units, and that safe décommissioning of the Haddam Neck plant is not possible given the defective nature of the design and licensing basis for this facility. In adeition, in the amendment the Petitioners assert that certain nitrogen calculations performed by NU for the Haddam Neck facility may not comply with 10 CFR Part 50, Appendix B, and that the NRC failed to identify this problem. The videotape records an August 29, 1996, Citizens Regulatory Commission televised interview of a former Millstone Station employee. The interview included the former employee's views relating to NU's poor management in allowing: degradation of the material plant; poor radwaste practices resulting in potential radiation exposure to employees; and harassment intimidation and subsequent illegal termination of employees raising safety concerns.

Petitioners request the following actions: immediate suspension or revocation of NU's licenses to operate its nuclear facilities in Connecticut; investigation of possible NU material misrepresentations to the NRC; continued

shutdown of the NU facilities in Connecticut until the Department of Justice completes its investigation and the results are reviewed by the NRC and until the NRC evaluates and approves NU remedial actions; continued listing of the NU facilities on the NRC "watch list" should NU resume operation; barring any predecommissioning or decommissioning activity at any NU nuclear facility in Connecticut until NU and the NRC take certain identified steps to assure that such activities can be safely conducted; and initiation by the NRC of an investigation into how it allowed the asserted illegal situation at NU's nuclear facilities in Connecticut to exist and continue for more than a decade. In addition, in the amendment, Petitioners request copies of Connecticut Yankee's nitrogen calculations and an immediate investigation of the need for enforcement action for alleged violation of 10 CFR Part 50, Appendix B.

The issues in the Petition, as amended, are being treated pursuant to 10 CFR Section 2.206 of the Commission's regulations and have been referred to the Acting Director of the Office of Nuclear Reactor Regulation. As provided by 10 CFR Section 2.206, appropriate action with regard to these issues will be taken within a reasonable time. By letter dated January 23, 1997, the Acting Director denied the request for immediate suspension or revocation of the operating licenses for the NU nuclear facilities in Connecticut.

A copy of the Petition, the amendment to the Petition and a transcription of the videotape are available for inspection at the Commission's Public Document Room at 2120 L Street, N.W., Washington, DC 20037

and at the local public document rooms at (1) the Learning Resources Center, Three Rivers Community-Technical College, 574 New London Turnpike, Norwich, CT 06360, and (2) the Waterford Library, ATTN: Vince Juliano, 49 Rope Ferry Road, Waterford, CT 06385.

Dated at Rockville, Maryland this 23rd day of January 1997.

FOR THE NUCLEAR REGULATORY COMMISSION

Frank J. Miraglia, Jr.

Frank J. Miraglia, Jr., Acting Director
Office of Nuclear Reactor Regulation

October 30, 1996

EA No. 96-440

Mr. Ted C. Feigenbaum
Executive Vice President - Nuclear
c/o Mr. Terry L. Harpster
P.O. Box 128
Waterford, Connecticut 06385

SUBJECT: NRC AUGMENTED INSPECTION TEAM REVIEW OF THE UNDETECTED INTRODUCTION OF NITROGEN GAS INTO THE REACTOR VESSEL DURING PLANT SHUTDOWN REPORT NO. 50-213/96-80

Dear Mr. Feigenbaum:

On October 2, 1996, the NRC completed an Augmented Inspection Team (AIT) at the Connecticut Yankee Atomic Power Company. The enclosed report presents the results of that inspection.

The AIT was chartered to review the events surrounding the inadvertent decrease in reactor vessel water level during plant shutdown conditions. The team also reviewed other decay heat removal system challenges and equipment failures. The team developed a sequence of events, determined the safety significance of the events, and assessed the quality of response by the plant staff and management.

For approximately four days, control room operators were unaware that nitrogen gas was leaking into the reactor vessel and causing level to decrease. By September 1, 1996, reactor vessel level had decreased to approximately 3 feet below the reactor vessel flange. The decrease in reactor vessel level was potentially significant because a further decrease in level could have challenged the function of the operating decay heat removal system. While there were no actual public health and safety consequences of this event and adequate decay heat removal was maintained, the situation involving an unintended decrease in reactor water level in combination with the unavailability of decay heat removal equipment was safety significant.

The team identified several areas where operations performance was inadequate. Several operations procedures failed to provide adequate details or contained incorrect information. The absence of acceptable procedures was a contributing cause for both the nitrogen gas intrusion going undetected and for the inadvertent diversion of water from the reactor coolant system (RCS). Several of the events were exacerbated by plant operators failing to follow plant procedures, conducting activities without procedural guidance, or making inappropriate decisions. A lack of a questioning attitude resulted in the failure to promptly identify the nitrogen gas accumulation in the reactor vessel. The failure by more senior operators to convey expectations to less experienced field operators during pre-job briefings resulted in inappropriate equipment manipulation that either directly caused or contributed to these events.

Enclosure 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.:	50-213
License No.:	DPR-61
Report No.:	50-213/96-80
Licensee:	Connecticut Yankee Atomic Power Company P. O. Box 270 Hartford, CT 06141-0270
Facility:	Haddam Neck Station
Location:	Haddam, Connecticut
Dates:	September 3, 1996 - October 2, 1996
Team Leader:	J. Trapp, Senior Reactor Analyst
Inspectors:	E. Conner, Project Engineer R. DePriest, Reactor Engineer P. Habighorst, Resident Inspector J. Munro, Sr. Reactor Engineer, NRR T. Shedlosky, Senior Reactor Analyst
Approved by:	James T. Wiggins, Director Division of Reactor Safety

EXECUTIVE SUMMARY

Haddam Neck Station
NRC Inspection Report No. 50-213/96-08

Event Summary/Safety Significance:

The AIT (team) conducted an independent assessment of the circumstances surrounding the (1) undetected accumulation of nitrogen gas in the reactor vessel head; (2) two inadvertent diversions of reactor coolant system (RCS) inventory; (3) failure of a residual heat removal (RHR) pump; and (4) a leak on a RHR heat exchanger inlet valve body. These events all occurred between August 22 and September 4, 1996.

The team concluded that the combination of these events was safety significant. The operation of the RHR decay heat removal system is contingent upon maintaining adequate level in the reactor vessel. The accumulation of nitrogen gas in the reactor vessel head significantly reduced the water level in the reactor vessel. The decrease in reactor vessel level went undetected by plant operators for nearly 4 days. The team determined that systems used to mitigate a loss of the RHR system were also adversely affected by the nitrogen gas intrusion. However, the team determined that there were no actual public health and safety consequences of this event.

Operations:

The team identified several areas where operations performance was inadequate. Several operations procedures, used during shutdown conditions, failed to provide important detail or contained incorrect information. The absence of acceptable procedures was a contributing cause for both the nitrogen gas intrusion into the reactor vessel going undetected and for the inadvertent diversion of water from the RCS. The team noted several examples where operator knowledge and performance failed to meet acceptable standards. Several of the events were exacerbated by plant operators failing to follow plant procedures, conducting activities without procedural guidance, or making inappropriate decisions. A lack of a questioning attitude, in response to several indirect indications that the reactor vessel was not full of water, resulted in the nitrogen gas accumulation going undetected. The failure by more senior operators to convey expectations to less experienced field operators during pre-job briefings resulted in inappropriate equipment manipulation that either directly caused or contributed to these events. Due to the operators failure to fully appreciate the significance of these events, timely notifications to the NRC were not made.

Maintenance:

The team noted areas where maintenance support was not timely or effective. The team determined that plant maintenance failed to restore the failed "B" RHR pump to service in a timely manner. The unavailability of quality parts, vendor specifications, and repeated post maintenance test failures resulted in operating with a single RHR pump for over 3 weeks. The timely restoration of the RHR pump was important because only the redundant "A"

RHR pump remained available to provide the preferred decay heat removal method. The team also noted a few instances where maintenance staff failed to comply with procedures during the repair of the "B" RHR pump. The team concluded that the maintenance support for restoring the RHR pump to service was not timely.

The team also noted that the poor material condition of several isolation valves was a contributing cause for two of the events reviewed. Leaking valves allowed nitrogen gas to enter the reactor vessel and water from the RCS to be diverted to the containment sump. The large number of leaking valves noted during these events may be indicative of a broader problem with the material condition of valves whose primary function is for non safety-related equipment isolation. The failure of these valves to function properly resulted in several operator challenges. The team concluded that the maintenance support for maintaining isolation valves was not effective.

Engineering:

The support provided to the operators by engineering and technical support (E&TS) was not timely or effective. The condition of the temporary reactor head vent system was significantly degraded. Over the past several years, management failed to effectively respond to previous plant staff concerns and improve the vent header design. The E&TS organization also failed to establish appropriate design criteria or conduct proper system oversight to ensure that the system was functioning properly. The failure to establish a functional reactor head vent systems allowed nitrogen gas to accumulate in the reactor vessel. Absence of a direct means of monitoring reactor vessel level, for approximately 6 days while refueling activities were postponed, complicated the situation for the operators.

Management Oversight and Controls:

The failure by plant management and staff to fully appreciate the significance of this event resulted in a poor event response and in a delay in initiating an integrated event recovery plan. The team determined that the actions taken during and following this event to determine actual reactor vessel level were not timely. These actions included taking local reactor vessel level indication system (RVLIS) and core exit thermocouple (CET) readings and completing the special test to verify level. Delays were encountered in reinstalling control room RVLIS and CET indications and aligning a reactor coolant pump (RCP) for standby service. The actions implemented to monitor the operating RHR pump, following the "B" RHR pump failure, were also not comprehensive or timely. Delays were also experienced in initiating and staffing the independent review team that investigated these events.

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Report Details

1.0 INSPECTION OBJECTIVES

The objective of this inspection was to conduct an independent assessment of the circumstances surrounding the (1) undetected accumulation of nitrogen gas in the reactor vessel head; (2) inadvertent diversions of reactor coolant system (RCS) inventory; (3) failure of decay heat removal system components. Specific inspection objectives were provided to the team, by the Regional Administrator, in the AIT Charter (Attachment 1 of this report). The inspectors used NRC Inspection Manual Chapter 93800 as guidance for conducting this inspection activity.

2.0 BACKGROUND AND EVENT SUMMARY

Undetected Accumulation of Nitrogen Gas in the Reactor Vessel

A reactor shutdown was completed on July 22, 1996, in accordance with technical specifications (TS), to address design issues with the containment air recirculation fans. Following the shutdown, plant management decided to remain shutdown and to start the planned refueling outage.

The plant was in cold shutdown during this event. The residual heat removal (RHR) system was in service to remove decay heat. The "A" RHR pump was in service and the "B" RHR pump was in standby (later determined to have been inoperable). The reactor vessel head was installed and the RCS loop stop valves were closed. The reactor vessel level indication system (RVLIS) and core exit thermocouples (CETs) had been removed from service in accordance with refueling procedures. The integrity of the RCS and containment boundaries was not established; however, controls were in place to reestablish these barriers, if necessary.

The chemical and volume control system (CVCS) was aligned to provide the required boric acid flow path to the RCS. The charging pumps were not operating. The volume control tank (VCT) was isolated with a nitrogen cover gas at a pressure of 30 psig. The VCT was pressurized to provide an additional source of makeup to the RCS.

The RCS was depressurized and the vent header system was in service. The vent header system was connected to the reactor vessel head using a temporarily installed hose. The vent header system maintains a small vacuum to remove gasses from the RCS (See Figure 1 of this report).

The available RCS level indications were the hot and cold calibrated pressurizer level indications, a temporary standpipe on the pressurizer, and the cavity level instrument. The cavity level instrument and temporary standpipe are placed in service during shutdown conditions. The range of the cavity level instrument is from the bottom of the RCS loop to the top of the refueling cavity. The cavity level instrument does not provide a direct indication of reactor vessel level. The cavity level instrument will indicate the highest elevation of water in the RCS. When water is in the pressurizer, the cavity level instrument will indicate pressurizer level.

On August 28, 1996, nitrogen gas from the VCT began to enter the reactor vessel (See Figure 2 of this report). A Nuclear Systems Operator (NSO) was in the process of realigning certain CVCS valves to establish a new boric acid flow path. During this evolution, the NSO inadvertently opened the wrong manual valve (BA-V-355). This error caused water and nitrogen gas from the CVCS system to enter the RCS. Control room operators noticed an increase in RCS level and promptly instructed the NSO to reclose the valve. Closing the valve should have stopped the nitrogen gas from entering the RCS; however, the valve failed to fully close and nitrogen gas continued to leak into the RCS. Nitrogen gas continued to flow through the idle charging pumps and several leaking valves into the reactor vessel. The nitrogen gas accumulated in the top of the reactor vessel head. The rate of addition of nitrogen gas exceeded the removal capacity of the vent header system. Therefore, a nitrogen gas bubble began to grow in the top of the reactor vessel. The water displaced by the gas bubble was forced out of the reactor vessel and into the pressurizer. The transfer of water inventory from the reactor vessel to the pressurizer resulted in a decrease in reactor vessel level.

The rate of addition of nitrogen gas to the RCS decreased as the size and pressure of the nitrogen gas bubble increased. As the differential pressure between the VCT and RCS decreased, the leakage of nitrogen gas into the RCS also decreased. Likewise, the increase in RCS pressure caused the removal of nitrogen out of the vent header to increase. The rate of accumulation of nitrogen in the reactor vessel was decreasing prior to the termination of this event on September 1, 1996.

On August 29, 1996, in preparation for reactor vessel head removal maintenance activities, operators drained approximately 5000 gallons of water from the RCS. Later that day, the decision was made to postpone the refueling activities and 1000 gallons of water were added back into the RCS. The pressurizer level and cavity level indications following this addition were approximately equal to the indications before the 5000 gallons of water were removed. The 4000 gallon difference is indicative of the size of the nitrogen gas bubble in the reactor vessel. Indicated cold calibrated pressurizer level continued to increase (~8%) over the next 3 days, as nitrogen gas continued to displace water from the reactor vessel into the pressurizer.

On September 1, 1996, the nitrogen gas supply to the VCT was isolated in an attempt to identify the source of the relatively high nitrogen gas usage. The isolation of nitrogen gas to the VCT stopped the nitrogen leakage into the RCS. The vent header system now had the capacity to remove the nitrogen gas which had accumulated in the reactor vessel. The volume of nitrogen being removed from the reactor vessel was replaced by the water from the pressurizer. The pressurizer level rapidly decreased until the level indication was no longer on scale. Six RCS makeups were required, totalling approximately 5000 gallons, to stabilize pressurizer level. Stopping the nitrogen leakage and refilling the reactor vessel terminated this event.

Inadvertent Diversions of RCS Inventory

The team reviewed two instances where water was inadvertently diverted from the RCS. The first event occurred on August 22, 1996, and the second event occurred on September 4, 1996.

On August 22, 1996, a NSO was conducting valve manipulations to place the RHR purification system in service. The RHR purification system is used to filter the water in the RCS. The RHR system was inservice providing shutdown cooling. During the valve alignment, the NSO failed to complete a procedure step that required closing the purification pump suction isolation valve from the refueling water storage tank (RWST). The subsequent procedure step required opening the purification pump suction valve from the operating RHR system. When this valve was opened, approximately 500 gallons of RCS water were diverted from the RHR system to the RWST. The team concluded that this failure was caused by inadequate procedures, the absence of a pre-job briefing, and the failure of the NSO to properly follow the procedure.

On September 4, 1996, an event occurred where RCS water was inadvertently diverted from the RCS to the containment sump. Maintenance personnel were starting a preventive maintenance (PM) activity on two motor-operated containment spray valves (RH-MOV-34 and RH-MOV-23). The PM required the valves to be cracked off their closed seats. The valves are used to isolate the RHR system from the containment spray header. A downstream manual valve (RH-V-23A) was closed to prevent the RHR system flow from being diverted to the spray header. Approximately 30-40 minutes after cracking open the valves, a control room operator noticed a decrease in pressurizer level and an increase in containment sump level. The water was being diverted from the RHR system to the containment sump. The leakage path was through the cracked open valves (RH-MOV-34 & 23), through the closed manual isolation valve (RH-V-23A), and through an open drain line from the spray header to the containment sump. A total of 200-300 gallons of RCS inventory was inadvertently diverted to the containment sump. The operators closed motor-operated valves (RH-MOV-34 & 23) to stop the leakage and refilled the RCS.

Prior to the September 4, 1996 event, the licensee stopped all work that could adversely affect the function of the RHR system. The valve PM work was inappropriately performed despite the stop work order. The team concluded that the failure to properly implement the stop work order and the leaking isolation valve were the causes of this event.

Failure of Decay Heat Removal Components

The RHR system is used to remove decay heat from the fuel when the reactor is shutdown. The system is designed such that a single failure, of certain components, will not prevent the system from performing its decay heat removal function. At the same time there was a nitrogen gas bubble in the reactor vessel, one redundant RHR pump and heat exchanger were not available for service (See Figure 3 of this report).

On August 31, a NSO identified a small amount of leakage from the "A" RHR heat exchanger inlet valve (RH-V-791A) body. The valve was closed to isolate the leakage. Closing the valve isolated the heat exchanger and removed it from service. The RHR system continued to remove decay heat using the redundant "B" RHR heat exchanger.

On September 1, 1996, the "B" RHR pump failed to operate after two start attempts. After each start attempt, control room operators manually secured the pump, when the expected motor ampere indications were not achieved. Plant operators were unsuccessful in there attempt to rotate the pump shaft manually. The operators concluded that the pump had become seized and was not operable. The RHR system remained inservice, removing decay heat, using the "A" RHR pump and the "B" RHR heat exchanger.

3.0 SAFETY SIGNIFICANCE

The team concluded that the combination of these events was safety-significant. However, there were no actual consequences of these events on the health and safety of the public and plant staff. This section of the inspection report provides a summary of the safety-significant aspects of these events.

Plant operators were unaware of the accumulation of nitrogen gas in the reactor vessel or the decrease in reactor vessel level for approximately 4 days. The inadvertent diversion of RCS inventory and the RHR system equipment failures further increased the significance of this event. The team concluded that it was fortuitous that the nitrogen bubble did not reach a size where RHR pump cavitation would occur. Had the nitrogen addition rate been increased or the vent header removal rate been decreased, the nitrogen bubble could have continued to expand in size.

The operation of the RHR decay heat removal system is contingent upon maintaining adequate level in the reactor vessel. Had the nitrogen gas bubble continued to expand in size, the nitrogen could have been entrained in the RHR pump suction, causing the operating "A" RHR pump to cavitate. The control room indications for a cavitating RHR pump would be fluctuations in motor ampere readings and a low RHR flow alarm. If the operators properly diagnosed gas entrained in the pump suction, then the correct response would be to secure and vent the pump. However, plant operators would have been presented with conflicting indications regarding pump cavitation during this event. The pressurizer level, on both the cavity and pressurizer level indications, erroneously indicated that the reactor vessel was full of water. Therefore, plant operators would not have expected that low reactor vessel was causing pump cavitation. If prompt operator actions were not taken, the only operable RHR pump could be damaged by the cavitation. If the RHR system were lost during this event, the time for the RCS to heat-up to 200 °F was approximately 52 minutes.

The abnormal operating procedure for a loss of RHR requires that the cavitating pump be secured and vented. However, the location of the RHR pump vents was not optimal and significant difficulty was encountered during venting the "B" RHR pump following maintenance to address its seizure. Therefore, an effective venting of a RHR pump may not have been easy to achieve. Throughout this event, the "B" RHR pump would not have been available for service. The operators were unaware that the "B" RHR had seized following its last operation on August 19, 1996. The failure of the "B" RHR pump added to the significance of this event. If the "A" pump was damaged, the RHR system would not be available to remove decay heat. All the RHR support system equipment, such as, emergency power, component cooling, and service water were available throughout the duration of this event.

If the RHR system were available to remove decay heat, plant procedures require pressurizing the RCS to facilitate natural circulation cooling using a steam generator as a heat sink. However, a prerequisite for this evolution requires filling the pressurizer using the charging pumps. During this event, nitrogen gas had displaced water in the charging pumps and the pumps would not have operated until the CVCS was vented and refilled. An additional potential consequence of the nitrogen gas in the RCS was that the gas could have entered the steam generators and obstructed natural circulation. The reactor coolant pumps had been removed from service and would not have been readily available to remove the nitrogen gas from the steam generators. If the steam generators are not effective in removing decay heat, plant procedures direct the use the low pressure safety injection pump (LPSI) to provide decay heat removal.

A decay heat removal path using the LPSI pumps and the RHR heat exchangers would have remained available. This flow path provides water pumped by a LPSI pump from the RWST to the RCS. Reactor coolant is letdown from the hot leg, through the RHR/RCS isolation valves, through the idle RHR pump and heat exchanger, and back to the RWST. The team concluded that this would have been an available decay heat removal method.

The inadvertent draindowns of the RCS inventory also contributed to the significance of this event. For the specific draindown events that occurred, plant operators stopped the diversions before a significant amount of water was removed from the RCS. However, had the diversions not been stopped, these events could also have caused RHR pump cavitation.

4.0 SUMMARY OF CONTRIBUTING CAUSES FOR EVENTS

The team identified several contributing causes for these events. This section of the report provides a brief summary of the contributing causes. The contributing causes are described in detail in subsequent sections of this inspection report. The section of this report that provide supporting information for the assessments are noted in parenthesis.

I. Operations

Operations Procedures and Documentation

Inadequate Procedures

The team concluded that poor quality operating procedures were a contributing cause for several operator errors. Poor procedure quality was a contributing cause for the operators' failure to detect the nitrogen gas accumulation in the reactor vessel in a timely manner. The lack of adequate procedures was the root cause for one of the two inadvertent RCS draindown events. The team concluded that the large number of procedure deficiencies may be indicative of a broader problem with procedure quality. The inadequate procedures were all infrequently used procedures for plant shutdown and draindown evolutions.

The operators compensated for a lack of detailed procedure guidance by writing instructions in accordance with administrative control procedure (ACP) 1.2-5.3, Evaluation of Activities\Evolutions Not Controlled by Procedure. The instructions written in accordance with ACP 1.2-5.3 do not require the same level of review and approval that other plant procedures receive. Operators wrote instructions for the draindown of the RCS and the venting of the charging pumps using the guidance in ACP 1.2-5.3. The team concluded that the guidance written for the RCS draindown did not provide adequate detail. Specifically, the guidance did not require RCS inventory balances, specify reference levels, or verify proper head vent operation. The team concluded that using ACP 1.2-5.3 to develop guidance for these activities was not consistent with regulatory requirements. The failure to provide detailed procedures contributed to the failure by plant operators to identify the accumulation of nitrogen gas in the reactor vessel. (Sections O3.1 and O3.3)

The team determined that the normal operating procedures for the vent header system, RHR system, and RHR purification system provided insufficient detail or incorrect information. The vent header operating procedure specified using equipment that was not installed in the plant, provided inaccurate system sketches, did not specify design requirements for temporary equipment, and did not require periodic monitoring of system performance. The RHR system operating procedure failed to provide specific guidance for shifting RHR pumps, establishing maximum allowable flow rates, removing a heat exchanger from service, and venting the pump. The lack of necessary step completion signature locations in the RHR purification procedure contributed to the August 22, 1996, RCS flow diversion. (Sections O3.2, O3.4, and O3.5)

Operator Knowledge and Performance

Failure to Implement Procedures

The team noted instances where activities were not properly conducted in accordance with procedures. In other cases, activities were conducted without having a procedure.

On August 28, 1996, the failure by a NSO to properly align a boric acid flow path, resulted in the inadvertent injection of water and nitrogen into the reactor vessel. The boric acid flow path alignment was not conducted in accordance with the procedure. This error was significant because the valve continued to leak by and allowed nitrogen gas to accumulate in the reactor vessel. (Section O4.5)

A plant procedure required measuring boron concentration in the RCS loops prior to opening the loop stop isolation valves. The failure to follow the procedure for collecting the boron samples resulted in inaccurate boron measurements. The boron samples are required to ensure that the RCS boron concentration is not inappropriately reduced when the loop stop valves are opened. (Section O4.2)

The team noted that nitrogen gas was isolated to the VCT and the RCS loop stop relief valves were isolated without using procedures. Closing the loop stop relief isolation valves was an inappropriate action because it isolated the necessary pressure relief capability for isolated sections of the RCS. (Section O4.1)

Lack of a Questioning Attitude

The team concluded that control room indications were available to identify the accumulation of the nitrogen gas in the reactor vessel. The failure to properly diagnose abnormal control room indications was a contributing cause for this event.

Plant operators failed to properly diagnose the cause of RCS level indication anomalies. Pressurizer level indication continued to increase for 4 days without any corresponding additions of water to the RCS. The operators erroneously concluded that the level increase was the result of leaking loop stop isolation valves and manually tightened down on these valves. The operators failed to monitor plant indications, following the completion of this action, to verify that the desired result of stopping the in-leakage was achieved. (Section O4.1)

On August 29, 1996, approximately 4000 gallons of water were removed from the RCS without a significant change in RCS indicated level. The operators failed to identify or evaluate this anomaly. The team determined that this anomaly offered another opportunity to have identified the existence of the nitrogen gas in the reactor vessel. (Section O4.1)

The source of the relatively high nitrogen gas usage was not investigated in a timely manner. High nitrogen gas usage began on August 28, 1996, and continued until the source of the leakage was identified and isolated on September 1, 1996. There was not an aggressive effort to identify the source of the high nitrogen usage before September 1, 1996. (Section O4.7)

Inappropriate Decision Making

The team noted examples where the plant staff failed to make conservative decisions. These failures to make conservative decisions resulted in an inadvertent diversion of RCS inventory and improper isolation of overpressure protection for portions of the RCS.

On September 2, 1996, the Unit Director placed a stop work order on any work that could adversely affect the RHR system's decay heat removal function. Contrary to the stop work order, plant work control supervisors and control room operators incorrectly allowed maintenance activities to be performed on the RHR system containment spray motor-operated valves. This maintenance activity resulted in the diversion of RCS inventory to the containment sump. (Section O4.6)

A second example of inappropriate decision making occurred on August 29, 1996, when operators isolated the loop stop pressure relief valves. These valves were closed in an attempt to stop a perceived in-leakage from the isolated RCS loops. The plant operators failed to properly evaluate the consequences of isolating the pressure relief valve for a water solid system. (Section O4.1)

Inadequate Pre-Job Briefings

The failure to conduct pre-job briefings adversely impacted job performance. The improperly performed evolutions were both being performed by the NSOs for the first time.

On August 22, 1996, a NSO failed to properly align valves while placing the RHR purification system inservice. The NSO was unaware of the proper procedural steps that needed to be performed. The lack of a pre-job briefing allowed the NSO to proceed with the valve alignment without the benefit of a thorough understanding of the activity to be performed. (Section O4.4)

The second instance where the failure to conduct a pre-job briefing resulted in poor performance occurred during a boric acid flow path valve alignment on August 28, 1996. During this evolution, the NSO manipulated the wrong valve, that resulted in the injection of water and nitrogen gas into the reactor vessel. By not conducting a pre-job briefing, shift supervision failed to provide expectations and guidance to the NSO. (Section O4.5)

Failure to Report Event

The team concluded that plant operators failed to make the appropriate prompt report to the NRC following the identification of the nitrogen gas bubble in the reactor vessel on September 1, 1996. 10 CFR 50.72 (b)(2)(iii)(B) requires a 4-hour event report be made for "Any event or condition that alone could have prevented the fulfillment of the safety function or structures or systems that are needed to: (B) Remove residual heat." The team determined that the nitrogen gas in the reactor vessel could have prevented the RHR system from removing residual heat. Therefore, this event was reportable. The Connecticut Yankee (CY) licensing staff determined that this event was reportable and a 50.72 report was made on September 11, 1996, 10 days following the event. (Section O4.8)

Operator Training and Qualifications

Failure to Conduct Planned Training

The team concluded that the failure to complete planned operator requalification training may have contributed to the operators inability to properly diagnose the indications of nitrogen gas in the reactor vessel.

The planned operator requalification training was postponed due to the unanticipated early start of the outage. The training material included a discussion of NRC Information Notice 94-36, Undetected Accumulation of Gas in Reactor Coolant System. This information notice provided information on expected plant indications with nitrogen gas in the reactor vessel during shutdown conditions. (Section O5.1)

II. Maintenance

Conduct of Maintenance

Avoidable Delays During the RHR Pump Repair

The "B" RHR pump was not returned to operable status until September 25, 1996, 25 days following the identification of its failure. The team noted several avoidable delays were encountered during the "B" RHR pump repair. Some of the delays included a lack of quality replacement parts, inadequate vendor supplied information, lack of technical evaluations for floor block removal, and the absence of appropriate vent locations. Further delays were encountered following pump reassembly when the motor end bell was found cracked. A thorough inspection of the motor in parallel with the pump maintenance could have prevented this delay. Problems encountered as a result of an improperly installed bearing oil seal, also caused further delays. (Section M1.1)

Material Condition of Facilities and Equipment

Poor Plant Equipment Condition

The team concluded that the failure of valves to isolate flow and the poor condition of the temporary reactor head vent system were root causes for these events.

The team noted several valves in the CVCS and RHR that failed to perform their isolation function. The leaking CVCS valves allowed nitrogen gas to enter the RCS. Leaking RHR valves allowed water from the RCS to be diverted into the containment sump.

The team also identified significant inadequacies in the design and operation of the temporary reactor head vent system. There were no documented design specifications for the system. The team identified several design deficiencies including using an inappropriate diameter temporary hose, using duct tape to prevent tygon tubing from kinking, operating the system with known loop seals, and not having the capability to automatically drain the system. The team also identified several deficiencies with the operation of the system including condensate in loop seals, lack of appropriate level in moisture dropout tanks, and kinked tygon tubing. The team determined that the overall absence of quality in the installation and operation of the reactor head vent system seriously degraded its ability to remove gas from the reactor vessel. A properly designed, maintained, and operated reactor head vent system may have removed the nitrogen gas from the reactor vessel and prevented this event. (Section M2.1)

III. Engineering

Engineering Support of Facilities and Equipment

Untimely Technical Response

The team concluded that certain aspects of the technical support response to these events were not timely. The following are examples where the team concluded that a more timely response would have been appropriate. (Sections E2.1, E2.2, and E2.3)

Local RVLIS and CET readings were not taken until September 3, 1996, two days following the identification of nitrogen gas in the reactor vessel. The local RVLIS and CET readings were taken with available test equipment and existing procedures. The team noted that confusion among plant staff on the ability to collect this information contributed to this delay.

A reactor coolant pump (RCP) could be used to provide forced circulation of the RCS in the event that the RHR system became unavailable. The RCPs could also be used to fill the steam generator U-tubes if nitrogen gas accumulates in the steam generators. A RCP and associated support systems were not aligned for service for 2 days following the identification of nitrogen gas in the reactor vessel. The alignment of the RCP was not a simple evolution and required considerable time. The team determined that the technical response to this event was not proactive in aligning contingency equipment to respond to a potential loss of the operable RHR pump.

The technical support organization developed two special test procedures to determine reactor vessel level and to verify that the reactor vent was not blocked. These tests were not completed in a timely manner. The tests were not completed until September 5, 1996, four days following the event.

The team concluded that the technical support for developing additional monitoring of the only operable RHR pump was inadequate. The technical staff provided no recommendations for additional monitoring of the operating RHR pump for 6 days following the identification of the failure of the "B" RHR pump. The additional monitoring that was implemented was to have the NSO observe pump operation 4 rather than the normal 3 times per day. The team concluded that additional non-intrusive pump performance monitoring could have provided additional assurances of proper RHR pump operation.

Poor Implementation of Generic Information

The United States Nuclear Regulatory Commission (NRC) issued Information Notice 94-36 describing a 1993 event at another nuclear power plant where nitrogen gas from the VCT accumulated in the reactor vessel. In response to the notice, the technical support staff at CY conducted a detailed evaluation of the information notice and provided several recommendations in 1994. The recommendations included maintaining at least 1 channel of RVLIS available when the VCT cannot be maintained isolated. The evaluation also recommended that "Operations Department should review the applicable shutdown

procedures to ensure that guidance is given to operators warning them of the potential for gas void formation in certain plant conditions and provide steps to ensure that monitoring for a void occurs." These recommendations were not adequately implemented prior to this event. The team concluded that implementing these actions may have provided operators the information needed to have identified and mitigated this event. (Section E2.4)

Weak Engineering/Operations Interface

The team identified several occasions when operators failed to solicit assistance from the E&TS organization. In other cases, E&TS failed to be proactive in providing operator support. The team determined that soliciting E&TS assistance would have been appropriate for identifying the source of the excessive nitrogen gas usage, evaluating the root cause for the increase in RCS level, and developing procedures for draining the RCS and venting the charging pumps. The E&TS organization failed to provide operators with an adequate reactor head vent system design or direct indication of reactor vessel level. Both of these deficiencies were previously identified in employee suggestions and generic information evaluations. In addition, a proactive E&TS organization, that was aware of system configuration changes, could have prevented the inappropriate maintenance activity on the RHR spray valves and the inappropriate closure of the RCS loop stop relief valves. The absence of an effective operations and E&TS interface was a contributing cause for these events. (Sections 5, O4.1, and O4.3)

Inappropriate Outage Scheduling Decisions

The team concluded that the decision to postpone refueling activities over the long weekend did not adequately include shutdown risk considerations. The outage schedule was delayed at a time when reactor vessel indications were disconnected and the steam generators were isolated. The team concluded that while the licensee had completed a detailed outage risk evaluation, that these insights were not properly considered when the decision was made to postpone the outage. (Section E2.5)

Lack of Direct Reactor Vessel Indication

The absence of direct reactor vessel monitoring instrumentation had an adverse affect on the operators ability to monitor reactor vessel conditions. The cavity and pressurizer level instruments do not provide a direct indication of reactor vessel level. The RVLIS, which does provide a direct reactor vessel level indication, was disconnected in preparation for refueling maintenance activities. The CETs are another direct indication of reactor vessel conditions. The CETs were also disconnected during the duration of this event.

The RVLIS indicates reactor vessel level at discrete elevations. During this event, the RVLIS would have indicated abnormal reactor vessel level when the actual level dropped below the reactor vessel flange. Following this event, local RVLIS readings were collected and a temporary jumper was purchased and installed to provide RVLIS indications in the control room. A second jumper was installed to provide CET indication in the control room. The team concluded that the failure to provide operators with direct indications of reactor vessel conditions was a contributing cause for this event. (Section 5, E2.1)

Quality Assurance in Engineering Activities

Slow Initiation of Event Response Team

The evaluation of these events by the CY staff was delayed. The initial response by licensee management was to conduct the event review using plant technical support staff. This team was later disbanded and an Independent Review Team (IRT) was chartered. This team was not fully staffed and functioning until September 4, 1996. The team concluded that the initiation of the IRT should have been more timely. The IRT had not completed its evaluation prior to the conclusion of the AIT onsite inspection activities on September 16, 1996. Therefore, the AIT did not assess the quality of the IRT efforts. (Section E7.1)

5.0 EVENT DETAILS

Detailed Sequence of Events

The team developed the following event sequence based on interviews, review of plant logs and operational data, and information from the licensee's IRT. Team comments and assessments regarding the events are provided in the bold and italicized text.

UNDETECTED ACCUMULATION OF NITROGEN GAS IN THE REACTOR VESSEL

July 22, 1996

The reactor is shutdown to address design issues with the containment air recirculation fans. Following the shutdown, plant management decides to start the planned refueling outage early. ***[The early start to the outage resulted in delaying requalification training. The team noted that the planned requalification training included a discussion of the indications of nitrogen gas in the reactor vessel. The team concluded that the delay in conducting this training was a contributing cause for this event.]***

July 27, 1996

The primary vent header is placed in service per normal operating procedure (NOP) 2.9-6, "Primary Vent Header Operation." ***[The vent header system is used to remove radioactive gases from the RCS during shutdown conditions. A temporarily installed hose is used to connect the reactor vessel head to the vent header. The reactor head vent hose is only installed when the RCS is depressurized. This system is not a safety-related system. This system was not intended to remove the large quantity of gas that was leaking into the RCS during the nitrogen intrusion event. The inability of this system to remove all the nitrogen gas from the reactor vessel, resulted in the accumulation of nitrogen in the reactor vessel. Several design and operational deficiencies were identified with this system by the AIT.]***

August 12, 1996

1241 The cavity level indicating system (CLIS) is placed in service. *[The CLIS provides control room level indication for the refueling cavity when the cavity is flooded. It also provides RCS level indication when the vessel head is installed during shutdown conditions. The CLIS variable leg is attached to a drain connection for the Loop #1 hot leg (LT-151A). The reference leg is attached to the reactor vessel head (LT-151C2) and compensates for vacuum in the vent header. The variable and reference leg transmitters are electronically subtracted to produce the cavity level signal. The cavity level indication readout is in inches elevation above sea level. A change of about 3.9 inches in cavity level is equivalent to 1% change in pressurizer level. The instrument scale is 170 to 600 inches elevation.]*

1638 The RCS loop stop valves are closed in accordance with plant procedures. *[Closing the loop stop valves isolates the steam generators and reactor coolant pumps from the reactor vessel. During this event, the closed loop stop valves prevented nitrogen gas from entering the steam generators.]*

August 25, 1996

0000 The liquid nitrogen storage tank level decrease is 2.5 inches during the previous 24 hours. *[This data establishes the baseline nitrogen usage in this mode of operation. The nitrogen usage after 8/28/96 increases substantially.]*

August 27, 1996

0034 The RVLIS and the CETs are disconnected. *[This was a scheduled maintenance activity in preparation for the removal of the reactor vessel head. The RVLIS system is the only direct reactor vessel level indication. The team concluded that the lack of a direct reactor vessel level indication was a contributing cause for this event.]*

August 28, 1996 (Wednesday)

The Technical Specification required boration flow path is from the boric acid metering tank (BAMT), through the CVCS metering pump, and into the RCS. *[The licensee is required to maintain one boric acid flow path available during this mode of operation. It was a misalignment of valves, while establishing a new boric acid flow path, which caused this event.]*

0628 The cavity level indication reading is 318 inches elevation. *[At this cavity level indication, the indicated pressurizer level would be approximately (~) 4% and the water level in the reactor vessel would be ~43 inches below the top of vessel and ~48 inches above the reactor vessel flange.]*

0630 The Unit Supervisor (US) briefs the operators and indicates that preparations are to be made to run the 2B emergency diesel generator (EDG). Procedure SUR 5.1-159B is used to align the boration flow path. *[A new boric acid flow path was required, because the metering pump will not be operable during the EDG surveillance. The licensee considers the EDG inoperable during the surveillance test. The emergency power for the metering pump is supplied by the 2B EDG. Therefore, the metering pump is also considered inoperable.]*

0800 A NSO is assigned the task of aligning the boric acid flow path. A formal pre-job briefing is not performed. *[The Unit Supervisor (US) believed that the NSO was only to verify that the existing valve lineup was correct. The NSO believed he had been given the authority to manipulate valves as necessary. The team concluded that the failure to conduct a formal pre-job briefing was a contributing cause for the error made by the NSO during the valve alignment. This was the first time that the NSO had performed this particular valve alignment.]*

The NSO simultaneously opens both valves BA-V-354 (Blended makeup to the VCT) and BA-V-355 (Blended makeup to the charging pump suction). *[The procedure does not allow these valves to be opened at the same time. The error in aligning these valves allowed nitrogen gas to leak into the RCS. The nitrogen gas pressure in the VCT was ~30 psid greater than the RCS pressure. This pressure differential provided the motive force to discharge water and nitrogen gas into the RCS. The water in the CVCS charging header was discharged into the RCS. After all the water was discharged from the CVCS system piping, nitrogen gas began flowing into the RCS. The hot calibrated pressurizer level indication increased from 0 to 10%. The team concluded that this was an example of an operator failing to follow procedures. A procedure requirement to contact the control room before manipulating valves was also not implemented.]*

The HIGH CAVITY LEVEL Alarm annunciates. The reactor operator, responds by increasing the alarm set point. The alarm came in a second time and the reactor operator contacts the NSO performing the boration flow path verification. Valve BA-V-355 is closed with the assistance of a valve wrench. *[Following this event, valve BA-V-355 continues to leak continuing the addition of nitrogen gas into the reactor vessel.]*

0845 The operators develop a procedure to vent the charging header and "B" charging pump using ACP 1.2-5.3, Evaluation of Activities/Evolutions not Controlled by Procedures. *[The charging header required venting because nitrogen gas from the VCT had displaced the water in the charging header. The team concluded that it was inappropriate to use ACP 1.2-5.3 to develop this procedure. Procedures developed in this manner do not receive the same level of review and approval as other station procedures.]*

0900 An adverse condition report (ACR) 96-0946 is prepared to document the valve manipulation errors made during the boration flow path alignment. ***[It was noted that while shifting boration flow path, VCT gas moved charging header water into the RCS. Pressurizer level increased about 2% and VCT pressure decreased about 2 psi with no level decrease. The team concluded that the operating crew should have solicited appropriate technical support to fully understand the cause and impact of this event.]***

The unit supervisor has a NSO verify that the condensate storage tank rupture disc or its supply is not leaking nitrogen gas. Nitrogen gas use increases to 9 inches in the past 24 hours. ***[This is the first documented indication that the operators were investigating the high nitrogen gas usage. The next documented indication occurs on September 1, 1996, when the VCT nitrogen supply was isolated. The team concluded that the plant operations staff lacked an appropriate questioning attitude and failed to solicit technical support in resolving the abnormally high nitrogen gas usage.]***

1333 The NSO completes venting the charging pump suction header. ***[The header required venting because nitrogen gas had entered the charging pumps when the inadvertent valve manipulation (event time 8/28 at 0800) allowed the nitrogen gas from the VCT to enter the charging pump header.]***

1422 The level in the pressurizer is increased approximately 2% with the metering pump to ensure the charging header was full of water. ***[The metering pump was run to transfer any left over nitrogen gas in the charging header into the RCS. This was performed to ensure the charging header was filled with water.]***

1602 The boration flow path alignment is completed. ***[The alignment was made using a different valve lineup independent of valves BA-V-354 and BA-V-355. The new boration flow path included the use of the "B" charging pump. However, nitrogen was continuing to enter this charging pump suction due to leakage through BA-V-355. The team concluded that the credited technical specification required boric acid flow path was not operable at this time. The flow path remained inoperable until the nitrogen was isolated from the VCT and the CVCS system vented on September 1, 1996.]***

1805 The cavity level indication reading is 323 inches elevation. ***[This is a 5 inch elevation increase since the 0628 cavity level reading. It was expected that cavity level would increase slightly as a result of the water added to the RCS during the valve alignment error and the CVCS refill.]***

1858 The 2B diesel generator surveillance test is performed. ***[This was a routine surveillance test that required the change in the boric acid flow path alignment.]***

August 29, 1996 (Thursday)

0600 The liquid nitrogen storage tank level decrease is 9 inches over the previous 24 hours. ***[This represented 3 times the normal usage recorded on 8/25. The team concluded that the plant staff failed to adequately investigate the source of the high nitrogen usage.]***

0646 The cavity level indication reading is 337 inches elevation. ***[This represents a 14 inch (~3% pressurizer level) increase in cavity level since the 8/28 at 1805 reading. This increase was caused by the accumulation of the nitrogen gas in the reactor vessel. The water from the reactor vessel was displaced into the pressurizer. The increase in water in the pressurizer caused the pressurizer level to increase. The team concluded that the plant operations staff did not adequately evaluate the cause of this level increase.]***

1025 Control room operators began intentionally draining water from the RCS. The water was being removed to reduce the water level in the reactor vessel to approximately the reactor vessel flange. The reduction in level was necessary to support the conoseal removal maintenance activity. A step list was developed by operators to drain the RCS. The step list was developed in accordance with ACP 1.2-5.3. Pressurizer level was decreased from approximately 10% to 2%. ***[The team determined that the licensee failed to have the required procedure for draining the RCS. The step list developed in accordance with ACP 1.2-5.3, did not require the same level of review and approval that a normal operating procedure receives. The team concluded that the lack of detail in the step list was a contributing cause of this event. The step list did not provide inventory balances, specify reference levels, or verify the operation of the vent header. A detailed procedure for draining the RCS could have resulted in a more timely identification of the nitrogen gas in the reactor vessel. The team concluded that this was an example where operations failed to solicit assistance from E&TS.]***

1120 Draining of the RCS is stopped at a cavity level indication of 299 inches elevation. The Shift Manager stops the draindown to confirm agreement between various level indicators. ***[At ~301 inch elevation the pressurizer level indication would go off scale low. The reactor vessel flange elevation is ~ 270 inches.]***

1400 The cavity level indication is ~321 inches (from ~2% pressurizer level to ~4% pressurizer level). ***[This increase in cavity level from ~299 inches at 1120 was caused by nitrogen gas entering the RCS and displacing RCS water into the pressurizer. The operators were unaware that the nitrogen gas in the reactor was the cause of the level increase.]***

1427 The loop stop overpressure relief valves are closed and the stop valves are manually tightened to prevent inleakage from the loops. ***[These valves were closed without procedural guidance and no engineering evaluation was performed. The team concluded that this was also an example of poor decision making. The loop overpressure relief valves were providing the overpressure protection for the isolated portions of the RCS.]***

The loop stop valves were known to leak during previous outages. The operators failed to adequately review the results of the valve closure to verify that the in-leakage had stopped. If the operators had reviewed these actions they would have concluded that loop stop valve leakage was not the source of the level increase. The team concluded that this was a missed opportunity to have identified the nitrogen leakage. Operations should have solicited E&TS assistance to evaluate the increase in pressurizer level.]

1455 The RCS draindown continues to the target value of approximately the reactor vessel flange. ***[The flange elevation is approximately 270 inches. The indicated pressurizer level would be off scale low at this elevation. Water would remain in the bottom of the pressurizer and the surge line would remain full.]***

1609 The RCS draindown is stopped. The cavity level is ~265 inch elevation. ***[The team verified the licensee estimates that a total of ~5000 gallons of RCS inventory was removed during the draindown evolution, based on the aerated drains tank level increase.]***

1800 The operators noted that cavity level indication is increasing and pressurizer level is coming on scale. During this abnormality, an NSO verified no water in the head vent, no changes in VCT pressure or temperature, and no change in RWST level. The operations crew incorrectly attributed the inventory increase to leakage from the loop isolation valves and the overpressure relief valves. ***[The team concluded at this point the operators should have solicited technical support assistance. With indicated cavity level at 282 inches, pressurizer level should have been off scale low. The cavity level indication should not have been increasing.]***

2000 Cavity level indication reading is ~299 inches elevation. No water was added to the RCS and cavity level is back to the elevation it was at before the second draindown. ***[The team concluded that the control room operators failed to adequately evaluate this increase in indicated cavity level. The increase was being caused by the nitrogen gas displacing vessel inventory into the pressurizer.]***

Plant management makes the decision to suspend refueling activities over the weekend. The operators were directed to refill the RCS. ***[The team concluded that the decision to delay refueling activities did not properly include risk considerations. A previous analysis of outage activities indicated that this was a relatively high risk period during the outage. The team concluded that to discontinue outage activities at this time was inappropriate.]***

2030 Operators add ~1000 gallons of water to the RCS in three separate makeups. After the makeups, the cavity level indication is at ~316 inches elevation. Before the RCS was drained the cavity level indication was at ~324 inches elevation. ***[Given the decision to delay refueling activities, the decision to restore RCS level over the weekend was appropriate. However, a 4000 gallon discrepancy existed between the 5000 gallons removed and the 1000 gallons added to the RCS. A eight inch difference in cavity level (difference between before and after letdown and makeup) indication would only account for ~500 gallon inventory difference. The team concluded that the lack of an inventory balance in the draindown step list and the failure of a questioning attitude by the plant operations staff allowed this discrepancy to go undetected. The 4000 gallons discrepancy provides an indication of the volume of the nitrogen gas bubble in the reactor vessel.]***

August 30, 1996 (Friday)

0000 The liquid nitrogen storage tank level decrease is 18 inches over the previous 24 hours. ***[The nitrogen gas is used for many purposes throughout the plant. The daily change in nitrogen gas use appears to be the result of nitrogen being supplied to various other equipment. However, the majority of the nitrogen gas was leaking into the RCS.]***

0416 The four loop overpressure isolation valves are opened. ***[This reestablished the normal valve lineup. These valves had been closed at 1427 on September 29, during the attempt to stop perceived leakage from the steam generators. These valves were inappropriately left closed for ~13 hours.]***

0719 The cavity level indication reading is 320 inches elevation. ***[This is a 4 inch increase in cavity level reading since 8/23 at 2030. The cause of this increase was the increase in nitrogen gas accumulation in the reactor vessel.]***

1800 The cavity level indication reading is 330 inches elevation. ***[The cavity level indication continued to increase as nitrogen gas continued to accumulate in the reactor vessel.]***

August 31, 1996 (Saturday)

0000 The liquid nitrogen storage tank level decreases 19 inches over the previous 24 hours. ***[The operators knew that nitrogen usage had increased without explanation, and that cavity level was trending in an unexpected manner. This information was not appropriately acted upon.]***

0800 The cavity level indication reading is 338 inches elevation. ***[The cavity level indication continued to increase as nitrogen gas continued to accumulate in the reactor vessel.]***

1600 The cavity level indication reading is 344.8 inches elevation. *[The cavity level indication continued to increase as nitrogen gas continued to accumulate in the reactor vessel.]*

September 1, 1996 (Sunday)

0000 The liquid nitrogen storage tank level decrease is 9 inches over the previous 24 hours. *[The majority of the nitrogen gas was being supplied to the VCT. The nitrogen from the VCT leaked into the reactor vessel. The vent header system was removing most of the nitrogen gas from the reactor vessel.]*

0600 The cavity level indication reading is 346.1 inches elevation. *[The nitrogen gas bubble in the reactor vessel head appears to be reaching an equilibrium condition where the nitrogen gas inleakage equals the venting capacity. The cavity level indication has only increased ~2 inches in the past 14 hours.*

The cavity level indication had increased from 316 inches after the last makeup on 8/30. This is equivalent to an ~7.5% rise in pressurizer level. At this point the reactor vessel level reached its minimum level of approximately 39 inches below the reactor vessel flange. This is ~2 1/2 feet above the top of the RCS loops and ~7 feet above the top of the fuel assemblies.]

A NSO informs the US of the abnormally high use of nitrogen gas. Plant operators systematically isolate and unisolate nitrogen gas supplies to various equipment. *[A procedure was not used for identifying or isolating nitrogen to various components. The system engineer was not involved in this activity. The team concluded that this was an example of operators conducting activities and evolutions without procedures. In addition, this is also an example where operators failed to solicit appropriate E&TS assistance.]*

0900 The nitrogen gas supply to the VCT is isolated in response to a NSO report of high nitrogen flow noises through the VCT nitrogen regulator. When the nitrogen gas is isolated, the cavity level indication decreases and pressurizer level decreases off scale low. *[The pressurizer level decreases because the nitrogen gas in the reactor vessel is being displaced by water from the pressurizer. When the nitrogen gas entering the reactor vessel was stopped, the vent header removed the nitrogen gas that had accumulated in the reactor vessel.]*

The control room operators directed the NSO to reopen the nitrogen supply regulator to the VCT slowly. This evolution is completed in ~20 minutes. *[The operators stated that they wanted to return the system configuration to that which existed before RCS level decrease.]*

1010 The operators commence adding water to the RCS using the RHR suction from the RWST (MOV-21) to refill RCS. *[A total of six makeups were needed during the next 3 hours to stabilize pressurizer level. Each RCS make-up filled the pressurizer to approximately 10%. After the make-up was stopped, the pressurizer level*

decreased off scale low and another refill was required. The sixth refill resulted in a stable 10% pressurizer level. The level in the pressurizer decreased as nitrogen gas in the reactor vessel was being removed by the vent header. Water from the pressurizer was replacing the nitrogen gas in the reactor vessel.]

1026 The operators believe that a RCS leak has occurred and implement abnormal operating procedure (AOP) 3.2-31A, Reactor Coolant System/Refueling Cavity Leak (Modes 5 and 6). A NSO is dispatched to inspect various systems for potential RCS leakage.

1029 A NSO drains a small amount of water from the reactor head vent hose. *[This indicated to the operator that the reactor vessel was full. This water was likely condensation from the vent header and not RCS inventory. At this point the reactor vessel head was not completely full. At 10% pressurizer level, the head is not expected to be full.]*

1030 Valve BA-V-354 (Blended makeup to the VCT) is closed to isolate suspected nitrogen flow through valve BA-V-355 (Blended makeup to the charging pump suction). *[This provided a two valve isolation of the nitrogen leak path. In addition, the VCT nitrogen pressure was reduced to about 4 psi.]*

1057 The operators complete the leak investigation using AOP 3.2-31A, Modes 5 and 6 Reactor Coolant System Leak. No leakage is identified from the RCS. Operators direct attention to gas flowing into the RCS. *[At this point, the operators realized that nitrogen gas in the reactor vessel had caused the decrease in pressurizer level.]*

1255 Operators complete the makeup to the RCS. The estimated amount of water added is ~5,000 gallons from the RWST. *[This inventory addition replaced the 4000 gallons lost during the draining evolution on 8/29. The additional 1000 gallons raised the pressurizer level above that which existed before the event began on 8/28.]*

1353 The operators document the receipt of the cavity low level alarm and use of AOP 3.2-31A in ACR 96-0966. *[The operators failed to appreciate the importance of these events. No effort was made to contact technical support for assistance. The team concluded that this was an example where operations failed to solicit the proper management and technical support.]*

1800 The cavity level indication is 348.8 inches elevation. *[This level would be equivalent to a pressurizer level of ~12% and a vented reactor vessel would be nearly full.]*

EVENT RESPONSE

September 1, 1996

1900 A conference call between licensee and NRC management is conducted to discuss the nitrogen gas event and other equipment failures.

September 2, 1996 (Monday Labor Day)

1200 A conference call between licensee and NRC management is conducted to discuss compensatory actions taken in response to the inoperable RHR pump and heat exchanger.

1400 The NRC AIT members arrive onsite.

The Technical Support Manager establishes an initial root cause team to review the nitrogen inleakage event and calls in the team members.

September 3, 1996 (Tuesday)

The Region I Regional Administrator establishes the AIT charter to formally investigate these events.

1000 A walkdown of the reactor vessel head vent header system by the NRC team identifies a kinked tygon tube, lack of adequate level in the loop seal of dropout tank TK-36-1A, and water in the vent line at the manometer in containment. The manometer in the Primary Auxiliary Building (PAB) indicates a vacuum of 14 inches which is normal. ***[The capability of the vent header system to remove the nitrogen from the reactor head was seriously degraded by these conditions. The team concluded that the failure to properly design, install and maintain the vent header system was a contributing cause of this event.]***

1200 Instrument and Control (I&C) technicians locally collect RVLIS readings using available test equipment and procedures. All 6 level indicators in the plenum region indicate full, the lower head probe (#2 at flange level) indicates full and the upper most probe (#1 Approx. 8" from top head) shows "some" level indication (train A was uncovered and train B was covered). ***[The team concluded that the failure to collect this information sooner was an example of the lack of a comprehensive and timely technical response to this event. The licensee appropriately continue to periodically take RVLIS readings.]***

Executive Vice President - Nuclear directs the Nuclear Safety and Oversight organization to establish an IRT. The IRT purpose and scope were established.

September 4, 1996

The IRT membership is finalized, a kickoff meeting held, and data-gathering commenced.

C532 Three CETs are placed in service. The CETs provide control room indication of temperatures above the fuel. *[In the event the RHR system was lost, the CETs would provide operators important information on the in-vessel conditions. The team concluded that the technical support organization should have been more timely in providing CET indication.]*

1600 The #3 RCP is placed in standby. *[In the event the RHR system becomes unavailable, the RCP could be placed in service to provide forced circulation. The RCP used in conjunction with the steam generator could be used to remove decay heat. A second decay heat removal method would be the use of the LPSI pumps and RHR heat exchangers. A closed decay heat removal cycle can be established with these systems and the RWST. The team determined that placing an RCP in standby should have been completed at an earlier time following the event.]*

September 5, 1996

A number of reactor head vent system fittings are replaced to improve system performance. *[The team noted that this change was performed without any technical review or official documentation.]*

The IRT is fully staffed. *[The licensee staffed the IRT with personnel without direct responsibility for normal plant functions.]*

1500 A special test is performed to verify reactor vessel level. This was performed using procedure ST 11.7-197, Determination of Reactor Vessel Level. *[The reactor required about 2236 gal (based on metering pump run times and flow rate), 1074 gal (based on increase in LI-402, pressurizer cold calibrated indication), 1,000 to 2,000 gal (based on RWST level decrease) before water started coming out of the vent hose. Cavity level system indicated an increase from 341 to 390 inches. The team concluded that these tests should have been completed in a more timely manner.]*

2101 After ST 11.7-197 was completed, the licensee drained about 725 gallons to the ADT. Pressurizer level decreased from 22% to 15% and cavity level changed from 390 to 360 inches.

September 6, 1996

A calculation to determine the minimum reactor vessel water level during this event is completed by operations. The calculation makes two initial condition assumptions that (1) the reactor level starts at 49%, and (2) the head is full. For the first case, the vessel level was calculated to drop to 39 inches below the reactor vessel flange. Using the assumption that the vessel is full results in a vessel level decrease to 20.5 inches below the vessel flange. ***[The team concluded that the first case with reactor level starting at 49% was the more appropriate assumption. A level of 39 inches below the reactor vessel flange is equivalent to the RCS level being ~2 1/2 feet above the RCS loops and ~7 feet above the top of the fuel assemblies.]***

1330 I&C reports RVLIS "A" and "B" channels both indicate 100% vessel level. ***[This indicates that the reactor vessel was full on September 5, 1996.]***

September 10, 1996

The IRT charter is approved. The data-gathering phase of the investigation is nearly completed and a time-line of significant events is being developed.

September 11, 1996

1504 The licensee makes a 10 CFR 50.72 event notification to the NRC on the introduction of nitrogen into the reactor vessel displacing inventory into the pressurizer. ***[The team concluded that this notification should have been made on September 1, 1996.]***

2018 The necessary electrical cable was purchased and Train "B" of RVLIS was placed in service. The RVLIS indicates 100%. ***The RVLIS system indication provides the operators direct vessel indication. The installation of this jumper would have provided the plant operators information that could have been used to identify and prevent this event. A jumper of this type was discussed in the licensee's evaluation of NRC Information Notice 94-36. The team concluded that the lack of direct vessel indication was a contributing cause for this event.]***

INADVERTENT DIVERSION OF RCS INVENTORY (August 22, 1996)

August 22, 1996

0740 The RHR purification system is shutdown to support a local leak rate test (LLRT). ***[The RHR purification system is used to filter the RCS when the RHR system is inservice.]***

2100 The LLRT is completed and operators prepare to restore the RHR purification system to service. *[A pre-job briefing of the NSO for the alignment of the RHR purification system valves was not performed. The NSO was performing this task for the first time. The team determined that the failure to conduct a pre-job briefing was a contributing cause for this event.]*

2110 The NSO opens the RHR purification pump suction valve from the RHR system (RH-V-874A) in accordance with NOP 2.7-4, Attachment 4, step 1.5. The NSO does not observe the expected purification system pressure increase and continues to open valve RH-V-874A one full turn. *[The NSO was unaware that step 1.4 of NOP 2.7-4, which closes the RHR purification pump suction valve from the RWST (PU-V-261A), had not been completed. The failure to close valve PU-V-261A, before opening valve RH-V-874A, resulted in a direct flow path from the operating RHR system to the RWST. Approximately 500 gallons of RCS water were inadvertently diverted to the RWST. The team concluded that the failure of the NSO to correctly implement this procedure was a contributing cause of this event.]*

2115 A CAVITY LOW LEVEL alarm annunciates in the control room. The control room operator observes that pressurizer level is decreasing. The control room operator immediately directs the NSO to close valve RH-V-874A. Closing valve RH-V-874A terminates the diversion event. *[The control room operators promptly identified and terminated this event. The failure to take prompt operator action could have resulted in RHR pump cavitation.]*

2130 The NSO returns to the control room and discusses the event with the US. The operators conclude that the NSO failed to complete the proper procedure step sequence. *[The team concluded that the poor quality of the NOP was a contributing causes for this operator error. NOP 2.7-4 did not provide step completion signature locations for steps 1.3 or 1.4. All the other procedure steps were provided with a signature location to indicate the step was complete. The absence of the step completion signature contributed to the NSO entering the procedure at the wrong step.]*

2222 The valve alignment for RHR purification system is completed correctly and the system is returned to service.

2234 An ACR 96-0926 is written to document this event.

INADVERTENT DIVERSION OF RCS INVENTORY (September 4, 1996)

August 18, 1996

A surveillance test is completed that strokes open and closed the RHR containment spray valves (RH-MOV-23 and RH-MOV-34). A downstream manual isolation valve (RH-V-23A) is closed to prevent water from the RHR system from entering the containment spray header. There is no leakage through valve RH-V-23A identified during this test. ***[This is significant because the manual isolation RH-V-23A is the valve that leaks by and causes the RCS flow diversion that occurs on September 4, 1996.]***

August 20, 1996

A clearance is written, but not applied, for conducting a preventive maintenance activity on valves RH-MOV-23 and RH-MOV-34.

August 29, 1996

1035 The work orders to disassemble valves RH-MOV-23 and RH-MOV-34 are released by operations to electrical maintenance.

September 2, 1996

The Unit Director/Operation Manager issued a partial stop work order on all work that could affect the RHR system or RCS inventory. The communications of the stop work order are done mostly by phone. Work control generates a list of work orders that needed to be called back to implement the stop work. The work orders for valves RH-MOV-23 and RH-MOV-34 are not called back. ***[This partial stop work order was issued to protect the RHR systems ability to remove decay heat. At this time the "B" RHR pump and the "A" RHR heat exchanger were known to be unavailable for service. The failure to call back these work orders was inappropriate.]***

September 4, 1996

0700 The Electrical Supervisor issues the work orders for valves RH-MOV-34 and RH-MOV-23 making them available for work. ***[Since the work orders were not pulled back, the Electrical Supervisor assumed that work could proceed on the valves.]***

1000 The lead electrician discusses the work with Administrative US. The Administrative US discusses the work with other control room operators. The Shift Manager was not informed. ***[The Administrative US and control room operators should have noted that work on these valves was not consistent with the stop work order and stopped this work activity.]***

1050 The control room operator cracks open valves RH-MOV-23 and RH-MOV-34. The lead electrician removes power to the valves at the breaker cabinet prior to entering containment to work on the valves. ***[The valves are used to isolate the operating RHR system from the containment spray header. A closed downstream manual valve (RH-V-23A), was to prevent the RHR system flow from being diverted to the spray header. The team concluded that the operator should have been aware of the condition of the RHR system and stop work order and should have not opened these valves.]***

1135 The Shift Manager notices pressurizer level decreasing and informs the US. The decrease in pressurizer level is confirmed by checking the cavity level (decreasing) and the containment sump (increasing). The lead electrician is contacted to get permission to reclose the valves. ***[The RCS was being diverted through the cracked open valves (RH-MOVs-23 and -34), leaking through the closed manual isolation valve, and into an open drain line off the spray header to the containment sump.]***

1140 Electrical power is restored to the valves RH-MOV-23 and RH-MOV-34 and the valves are closed. Closing these valves stops the leakage and terminates this event. ***[The plant recorder charts indicate a ~1.5% loss of pressurizer level and a ~5 inch loss in cavity level indication. The total inventory diverted from the RCS to the containment sump is estimated to be ~200 to 300 gallons.]***

1145 A NSO is dispatched to verify that valve RH-V-23A is completely closed. The NSO manages to close the valve, by hand, another 1/8 of a turn. Later in the afternoon, another attempt to close the valve further was made using a valve wrench, another ½ turn closed was made. ***[The failure to completely close this valve caused it to leak by. The team concluded that poor material condition, resulting in operators being unable to adequately close several manual valves and leaking manual isolation valves, was a root cause for several of the events reviewed.]***

1241 The containment sump is pumped and ~380 gallons of water are removed.

1320 An ACR 96-0978 is written that documents the RCS inventory diversion event. ***[The team concludes that, in addition to the failed work stoppage, the common manual RHR to containment spray isolation valve, RH-V-23A, leaking by its seat was a contributing cause of this event.]***

1530 A complete stop work order is issued from the Unit Director to all employees with a written explanation.

FAILURE OF DECAY HEAT REMOVAL COMPONENTS

July 29, 1996

1010 An inservice test is conducted on the RHR pumps. *[The "B" RHR pump was placed into the "Alert" range due to high vibration. An engineering evaluation of the vibration data was performed and the test frequency was changed from quarterly to monthly.]*

August 19, 1996

0730 The "B" RHR pump was started and run in parallel with the "A" RHR pump. *[The pump was run to cool down the RCS in preparation for the LPSI surveillance test. During the test the RHR pumps are secured. It appears that the final damage to the "B" RHR pump occurred during this pump operation.]*

0824 The "B" RHR pump is secured. *[This is the last time the "B" RHR pump was successfully operated before it was found seized on September 1, 1996. The operators stated that the pump did not display any abnormal indications during this operation. It is presumed that the pump was seized and incapable of operating from this time and remained unavailable until the pump was identified as failed on September 1, 1996.]*

August 31, 1996

0900 A NSO, while conducting routine rounds in the RHR pump area, identifies a small amount of water leakage from the "A" RHR heat exchanger inlet valve (RH-V-791A) body.

1100 ACR 96-0968 is written to document the leakage from valve RH-V-791A.

1352 The pin hole leak on the "A" RHR heat exchanger inlet valve RH-V-791A is reported under 10 CFR 50.72(b)(2)(i). *[TS Limiting Condition for Operation 3.4.1.4.2 entered because of inoperable RHR loop.]*

1440 Operators reduced RHR flow to 2190 gallons per minute (gpm) in preparation of isolating valve RH-V-791A. *[The RHR NOP failed to provide maximum flow rates with a single heat exchanger.]*

1532 Valves RH-V-791A and RH-V-794A are closed to isolate the "A" RHR heat exchanger. *[The "A" and "B" RHR pumps feed a common header, so any combination of pump/heat exchanger may be used to remove decay heat.]*

September 1, 1996

1419 The decision is made to start the "B" RHR pump, to allow the "B" RHR pump to operate with the "B" RHR heat exchanger.

The "B" RHR pump fails to operate on the first start attempt. A second start is attempted within a few minutes of the first and the second attempt also fails. During both attempted starts motor ampere indication remained off scale high (>400 amps) for no more than 5 seconds. An attempt to manually rotate the pump shaft identifies that the shaft would not turn. The "B" RHR pump is declared inoperable. ***[This reduces the cooling capacity of RHR to one pump ("A") and one heat exchanger ("B").]***

1448 ACR 96-0964 is written to document the failure of the "B" RHR pump.

1752 The RCS loops #3 and #4 cold leg stop valves are opened. ***[This was to provide a backup cooling method in accordance with procedures.]***

2124 RCS Loops #1 and #2 are unisolated (cold leg and hot leg isolation valves opened). ***[This step was one required for placing the steam generators in service as backup to the RHR system for vessel cooling. The team noted the failure to follow procedures resulted in the collection of inaccurate boron samples of the steam generator inventory. The steam generators are sampled to prevent diluting the water in the reactor.]***

September 2, 1996

Maintenance activities to repair the "B" RHR pump begin.

September 3, 1996

The spare RHR pump assembly is moved from the warehouse to the maintenance shop. ***[The spare replacement pump had concentricity and perpendicularity deficiencies between the bearing and head casings. The pump was shipped out to the vendor for repairs. The pump impeller required additional machining and balancing. The team determined that the unavailability of quality spare parts contributed to the significant delays the RHR pump replacement.***

The vendor specifications of the RHR pump were not readily available. The team concluded that the lack of vendor information on the pump resulted in several avoidable delays during the pump repair.]

September 4, 1996

1330 The floor blocks are removed to access the RHR pump for repair. The pump is removed from the casing. A visual examination identifies some wear on the circumference of the pump wear rings. ***[The team noted that the lack of an available technical evaluation for removing the RHR pump floor blocks resulted in a delay in the pump repairs and contributed to the length of time required for the pump repair.]***

September 7, 1996

The licensee issues TPC 96-570, Nuclear System Operator Primary Side Shutdown Logs, to require increased surveillance frequency (every 6 hours) of the "A" RHR pump oil levels, pit ambient temperature, and pit area status. ***[The team concluded that this action was appropriate but not timely. The team also believed additional non-intrusive surveillance measurements of the "A" RHR pump would have been appropriate.]***

September 9, 1996

Maintenance activities to machine the casing bore for the wear rings continued. Other ongoing activities include, making a new wear ring, and machining the inside diameter of the impeller.

September 11-13, 1996

9/11-13 The pump maintenance is delayed while waiting for vent valves for casing and bearing cooler line, wear ring, and other parts.

September 13, 1996

An ultrasonic non-destructive test (UT) is performed on the leaking RHR heat exchanger inlet valve (RH-V-791A). The casting wall thickness did not indicate any substantial wall loss.

September 14, 1996

The repairs and installation of the "B" RHR pump are completed.

1945 A post maintenance test is performed on the "B" RHR pump. The pump failed to pass the post maintenance test. The pump is stopped after approximately 10 seconds, when the indicated motor amperage is less than expected. *[The technical staff stated that the cause for the pump test failure may have been inadequate venting. The pump had been vented in accordance with the RHR system normal operating procedure. However, the pump vents are not located at the high points and the technical staff believed that poor vent location was the cause of the inadequate venting.]*

September 15, 1996

A procedure is written to allow the pump to operate for 2 minutes at the reduced motor amperage. This is to allow time for the pump to discharge any gas that may be present in the pump. The pump is instrumented with local flow and pressure indications. The pump is started and again indicates low motor amperage, no flow, and low discharge pressure for the first 90 seconds of operation. At 90 seconds, the pump appears to start pumping and normal flow, pressure and motor amperage readings are observed. The pump operated for a short time before the operator noticed low oil level in the thrust bearing oiler and the test was stopped. The post maintenance test is not successfully completed. *[The team concluded that the lack of appropriate pump vent locations contributed to the significance of these events. Had the nitrogen bubble grown to a point where nitrogen gas entered the RHR pumps, then procedures require securing and venting the pumps. The lack of adequate vent locations could have adversely impacted the ability to return a gas bound RHR pump to service.]*

September 16, 1996

The "B" RHR pump post maintenance test is performed. Test data indicated a problem with the pump motor. A visual inspection of the motor identified a crack in the motor endbell. The post maintenance test results show a test failure.

The AIT completes onsite inspection activities. *[Work on the "B" RHR pump continued for another 9 days after the team concluded the onsite inspection activities. The work performed included the replacement of bearing oil seals.]*

September 25, 1996

2100 The "B" RHR pump is declared operable. The pump was declared inoperable on September 1, 1996. *[The team noted that the pump maintenance was conducted in a methodical and conservative manner. However, several avoidable delays contributed to the extended repair duration.]*

O3 Operations Procedures and Documentation

O3.1 Reactor Coolant System Draindown

a. Inspection Scope

On August 29, 1996, the on shift operators conducted two RCS draining evolutions in preparation for reactor vessel head removal. The team reviewed the procedure used to drain the RCS written by shift management in accordance with ACP 1.2-5.3, Evaluation of Activities/Evolutions Not Controlled by Procedure, and discussed its performance with the cognizant operations Unit Supervisor (US) and the Reactor Operator (RO). Refer to section O4.1 of this report for NRC findings related to operator knowledge and performance for this activity.

b. Observations and Findings

Shift management used the guidance of ACP 1.2-5.3 and developed a seven step procedure to control the RCS draindown in preparation for reactor head removal. The procedure was developed by the US since no valve alignments were specified in the normal operating procedure (NOP) 2.3-4, Shutdown from Hot Standby to Cold Shutdown, to drain the RCS. The required actions included verification of RHR purification system operation, placing cavity level and local standpipe level indication in-service, stationing operators at each indicator, adjustment of the cavity low level alarm to 268 inches, and a draindown flow path through valve WD-V-210 to the aerated drains tank (ADT).

The team noted that the procedure failed to indicate a specific vessel reference level value for the draindown, to provide for reconciliation of inventory drained against an expected level indication change, and to require verification of reactor vessel vent header system operation prior to the RCS draindown. Furthermore, the procedure provided no information to control systems necessary for maintaining RCS inventory while at the refueling reference level. NOP 2.3-4 cautions prior to RCS draindown to not change any valve line-ups that might adversely affect the RHR system or RCS inventory while at the refueling reference level.

Technical Specification (TS) 6.8.2 requires that each procedure described in TS 6.8.1, including the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, and changes thereto, shall be reviewed by the Plant Operations Review Committee (PORC) and approved by the Vice-President - Haddam Neck prior to implementation. Appendix A of Regulatory Guide 1.33 specifically requires written procedures for draining the RCS. Contrary to TS 6.8.2, ACP 1.2-5.3 allows activities that require PORC review to be performed at the discretion of the Shift Manager (SM).

ACP 1.2-5.3 states that "This procedure is not intended to supplant existing procedures ... " and "...applies to activities that are currently outside established procedures." However, team discussions with operations personnel confirmed that NOP 2.3-4, step 6.4.16, provided the only existing guidance for draindown of the RCS.

The team made the following observations regarding the licensee's use of and performance of an ACP 1.2-5.3 procedure for RCS draindown:

- The licensee's failure to have the procedure reviewed by the PORC and approved by the Vice-President prior to implementation was in violation of TS 6.8.2.;

- The worksheet written instructions were in violation of ACP 1.2-5.3 since draindown of the RCS is addressed by an existing procedure - NOP 2.3-4; and,

- The worksheet written instructions were inadequate in not providing for reconciliation of inventory drained against an expected level indication change, verification of reactor vessel vent header system operation prior to RCS draindown, or control of systems necessary for maintaining RCS inventory while at the refueling reference level.

c. Conclusions

The team concluded that the ACP 1.2-5.3 written procedure guidance was inadequate for control of a RCS draindown evolution. The licensee failed to ensure the procedure guidance was reviewed and approved in accordance with TS 6.8.2, and the operators failed to question the lack of this review. The team concluded that the failure to have a detailed RCS draindown procedure was a contributing cause for this event.

O3.2 Reactor Coolant System Vent Header

a. Inspection Scope

The inspection scope was to review the existing procedural controls of NOP 2.9-6, Primary Vent Header Operation, and evaluate system operation in accordance with NOP 2.9-6 during a system walkdown by the team on September 3, 1996.

b. Observations/Findings

The team noted that no vacuum pump installation connections are available to support venting of the RCS loops, and the NOP 2.9-6 system alignment drawing did not match the field installation for the reactor vessel head connection. The team learned that the operation of RCS vent and the reactor head vent are not periodically verified, and only checked for moisture or loop seals if deviations occur between cavity level and pressurizer level indications. The above deficiencies were presented to the licensee during the inspection.

On September 14, 1996, the licensee revised NOP 2.9-6. The major changes to the NOP included: the establishment of a loop seal in containment vent header moisture drain tank; specific system valve alignments and guidance for connection to the loops, pressurizer, and pressurizer relief tank; independent verification requirements during the installation of the reactor head vent; installation of a vacuum compensator; and additional requirements for daily checks of the digital manometer, daily walkdown of the system hosing, twice weekly drainage of moisture from the vessel head vent, and a check for level in the moisture drain tank. The provision for a vacuum pump instead of the air eductor was removed from the procedure. The revised procedure approved by the PORC also included a technical evaluation for the changes and addressed the expected air removal capability of the system. The team verified that the system improvements were installed on September 14, 1996.

c. Conclusions

The RCS vent installation lacked adequate procedural guidance and controls. No procedurally required system checks occurred to verify acceptable operation prior to September 14, 1996. The team concluded that the failure to have a detailed procedure for the installation and operation of the vent header system resulted in the system being incapable of adequately removing all the nitrogen gas from the reactor vessel.

O3.3 Fill and Vent of the Charging System

a. Inspection Scope

On August 28 and September 1, 1996, the operators conducted a fill and vent procedure for the charging suction header and the "B" charging pump after an inadvertent injection of nitrogen into the charging system. The team reviewed the fill and vent procedure written by shift management in accordance with ACP 1.2-5.3 and discussed its performance with the cognizant operations US.

b. Observations and Findings

Shift management used the guidance of ACP 1.2-5.3 and developed a ten step procedure to fill and vent the charging suction header and the "B" charging pump. The team discussed the content of this procedure with the US and reviewed piping and instrument drawings. The licensee's IRT identified several questions regarding the adequacy of this procedure that required additional evaluation.

The developed procedure to fill and vent the charging system was not in accordance with TS 6.8.2.

c. Conclusions

The licensee failed to ensure the procedure guidance was reviewed and approved in accordance with TS 6.8.2, and the operators failed to question the lack of this review.

O3.4 Placing Residual Heat Removal Purification System In Service

a. Inspection Scope

On August 22, 1996, the cavity level indicator experienced an unexpected drop from approximately 325 inches to 273 inches. The cause of the event was the failure of a non-licensed operator to properly perform the RHR purification system valve alignment to restore the system from a temporary shutdown condition. The team reviewed Adverse Condition Report (ACR) No. 96-0926 and the resulting temporary procedure change (TPC), and discussed this review with the cognizant operations US. Refer to section O4.4 of this report for NRC findings related to operator knowledge and performance for this activity.

b. Observations and Findings

The purification system is designed to remove impurities from the RCS during plant shutdown and depressurization. On August 22, 1996, the system was placed in a temporary shutdown status in accordance with NOP 2.7-4, RHR Purification System Operation, to allow for testing of safety injection (SI) system check valves per surveillance procedure (SUR) 5.7-66. The RHR purification effluent discharges through the high pressure safety injection (HPSI) loop stop valves and associated check valves. Attachment 4 of NOP 2.7-4 provides guidance for both temporary system shutdown (steps 1.1 through 1.3) and subsequent restoration (steps 1.4 and 1.5). The system shutdown status checklist (step 1.3) isolates the purification system from the HPSI discharge line and opens the purification pump suction valve (PU-V-261A) from the RWST. This valve is reclosed in step 1.4, during performance of the purification valve alignment prior to opening the purification pump suction isolation valve, (RH-V-874A), from the RHR system in step 1.5 to reestablish system flow.

ACP 1.2-6.5, Station Procedures, advocates the use of personnel sign-off blocks for actions that are likely to be overlooked and includes actions that "make alignments" for consideration in the use of personnel sign-offs. NOP 2.7-4 did not require personnel sign-offs for completion of the valve alignments directed by action steps 1.3 and 1.4.

The licensee initiated an ACR and issued a TPC which added personnel sign-offs for steps 1.3 and 1.4, and clarified the purpose of step 1.4 with regard to system restoration.

c. Conclusions

The inspectors concluded that NOP 2.7-4 was inadequate although all procedural steps were found to be correct. The licensee failed to ensure the action steps required for system restoration were clearly identified and did not designate all system alignment steps for personnel sign-off as recommended by procedure ACP 1.2-6.5.

O3.5 Residual Heat Removal System Operation

a. Inspection Scope

The inspection scope was to evaluate the quality of operating procedures for the RHR system. In particular, the review evaluated the procedural controls and instructions for shifting RHR heat exchangers and pumps during a cold shutdown condition. The inspection consisted of interviews with operators and system engineering personnel.

b. Observations/Findings

The team learned that on August 31, 1996, the licensee isolated the "A" RHR heat exchanger from service due to a valve body leak on the manual inlet valve RH-V-791A. Later on September 1, the operators attempted to shift RHR pumps and identified the failure of the "B" RHR pump to start.

The procedural guidance in NOP 2.3-4 requires when RCS temperature is less than 120 degrees fahrenheit (°F) that RHR flow be reduced to 2000-2200 gallons per minute (gpm) and one of the two running RHR pumps be secured. NOP 2.9-1 initially establishes RHR flow for hot shutdown with two RHR pumps and two RHR heat exchangers operating.

On August 31, 1996, procedural guidance did not exist for shifting the RHR pumps once aligned in accordance with NOP 2.3-4, or for isolating one of the two RHR heat exchangers. Additionally, NOP 2.9-1 did not specify any limits for maximum RHR flow rates through the heat exchangers. The team reviewed the Updated Final Safety Analysis Report (UFSAR) and concluded that no design limitations were documented for maximum RHR flow through the heat exchangers. Prior to the operators isolating the "A" RHR heat exchanger, the RHR system engineer specified

maximum allowable RHR flow limits of 2200 gpm through any one heat exchanger (based on the design limits supplied by the vendor) and 3000 gpm per RHR pump to prevent pump runout. The operators isolated the "A" RHR heat exchanger from service, using general knowledge of heat exchanger operation and isolation, by shutting the RHR inlet valve and maintaining the RHR outlet valve open while continuing to supply cooling water flow through the heat exchanger.

The team also learned that NOP 2.9-1 did not provide specific instructions on venting of the RHR pump or its associated suction and discharge lines prior to starting a pump. During the attempt to start the "B" RHR pump on September 1, the operators did not conduct any specific venting evolutions for the "B" RHR pump. Operations Department Instruction (ODI)-1, Conduct of Operations, provides general guidance for venting pumps and piping high points whenever possible following draindown of a system or component. No draindowns of the system or the "B" RHR pump occurred between securing the pump and the attempted restart.

The RO attempted to start the "B" RHR pump and noted that the ampere indication in the control room maintained greater than 400 for approximately five seconds. The RO expected to see the ampere indication go off-scale at greater than 400 amperes for a couple of seconds and then come to a value of approximately 180 amperes. The RO secured the pump, consulted with the SM, and then attempted to restart the motor after approximately one minute. The restart attempt had the same indications of off-scale amperes. The RO again secured the pump. The SM sent a Nuclear System Operator (NSO) to "bar over" the pump shaft and to verify if any protective relays came in locally at the breaker in the "B" switchgear room. The NSO reported that the shaft did not move when "barred over." No protective relays were noted to have tripped at the breaker. ODI-1, section 5.3.8 provides guidance on resetting protective devices and states that if protective devices trip, an attempt should be made to understand the cause prior to resetting the device. For the "B" RHR pump no protective devices tripped during the start of the pump. The team concluded that the RO actions to restart the "B" RHR pump were not precluded by ODI-1. Based on a subsequent motor current spectrum analysis, no observed damage to the motor was identified by the licensee. The analysis verified that no rotor bar damage occurred during the short time that the motor experienced locked rotor current.

On September 13, 1996, the licensee approved revision 32 to NOP 2.9-1 which made the following major changes: upper flow limit established for RHR flow through a heat exchanger; attachments added to vent the RHR pump prior to starting or shifting pumps; and steps added to secure the one pump when both are no longer required.

c. Conclusions

The team concluded that NOP 2.9-1 was inadequate in providing guidance for shifting RHR pumps, upper RHR flow limitations, and isolation of heat exchangers. The licensee revised NOP 2.9-1 to address these procedural deficiencies.

O3.6 Boration Injection Flowpath Alignment

a. Inspection Scope

On August 28, 1996, during performance of an alignment check to verify an operable TS required boron injection flow path, a NSO incorrectly opened a valve that resulted in injecting water and nitrogen into the RCS. The causes of the event were an inadequate pre-job brief (discussed in O4.5) and the failure of the NSO to comply with all procedural precautions. The team reviewed the applicable surveillance procedure, SUR 5.1-159B, Boron Injection Path Valve Lineup and Metering Pump Test (Shutdown Modes 5 and 6), and discussed its performance with the operations personnel.

b. Observations and Findings

Procedure SUR 5.1-159B requires a verification that each valve in the TS required boron injection flow path that is not locked, sealed, or otherwise secured is in its correct position. On August 28, 1996, the existing injection flowpath was from the boric acid makeup tank (BAMT) via the metering pump to the RCS. This flowpath was to be rendered temporarily inoperable during the performance of preventative maintenance procedure (PMP) 9.1-31 on Emergency Generator (EG)-2B. EG-2B is the emergency source of electrical power for the metering pump. The NSO was directed to verify alignment of another operable injection flowpath from the BAMT via a boric acid pump and a charging pump to the RCS. However, the flowchart methodology is not a pre-determined valve line-up checklist and requires the operator to select the available flow path(s) from among several possibilities by applying knowledge of existing system and component status in answering questions regarding operability and availability, e.g., "BA Filter in Service? Yes/No." Procedure step 6.1.2 directs the operator to "VERIFY" that each component for the selected flowpath is in the required position but does not direct repositioning of any component. If a valve is not found in the position specified on the valve lineup checklist, precaution 5.1.1 directs the operator to immediately notify the shift supervisor and not to proceed until the situation is resolved.

According to the NSO's description of the occurrence, he believed that the direction of step 6.1.2, to verify each flowpath component in its correct position, authorized realignment of components as necessary and that precaution 5.1.1 did not specifically apply once the flowpath had been determined. As a result, the NSO repositioned valve BA-V-355 and injected water and nitrogen from the CVCS into the RCS. The licensee subsequently issued TPC No. 96-358 that added a note to flowchart 1 precluding valves BA-V-354 and BA-V-355 being open at the same time with valves CH-MOV-257 or CH-MOV-257B shut. Refer to O4.5 of this report for NRC findings related to operator knowledge and performance.

c. Conclusions

Operations procedural guidance for verification of an operable TS required boron injection flow path was adequate. Adequate direction is placed in the SUR procedure to preclude component repositioning during flow path verification. However, due to the many system and component line-ups possible during an outage, the procedure relies on the operator to recognize and understand system and component status for proper performance. The causes of the event were an inadequate pre-job brief and the failure of the NSO to comply with all procedural precautions.

O3.7 Loss of Residual Heat Removal

a. Inspection Scope

The inspection team reviewed the abnormal operating procedure for a loss of the residual heat removal system.

b. Observation/Findings

The licensee has established an abnormal operating procedure, AOP 3.2-12, Loss of Residual Heat Removal. This procedure has initial conditions of the reactor in Mode 5 or 6, cold shutdown and refueling, respectively. Its initial strategy involves diagnosis of plant conditions and actions to restore the RHR system, including restoration of power, component isolation and pump suction venting.

The licensee developed a plant condition action matrix within the procedure that directs the operator to perform actions that establish alternate means of decay heat removal, depending on the plant conditions and what is known about the RHR system. The procedure plant condition action matrix directs the operator to a specific decay heat removal recovery action. Had the RHR system failed during the period of interest covered by this inspection, the operations staff would have attempted recovery by isolating and pressurizing the RCS and establishing a heat sink with a steam generator with natural circulation or forced cooling with a RCP. Had this primary method failed, the procedure directs the operators to alternate methods. Feed and bleed cooling of the reactor core would be attempted with a charging pump. The RCS would be pressurized and coolant discharged through a low temperature overpressure protection (LTOP) relief valve. Then, forced cooling would be attempted with a LPSI pump and the RHR heat exchangers.

In order to address various contingencies, AOP 3.2-12 addresses contingencies of filling RCS loops with a charging pump or by gravity feed, unisolating an RCS loop, natural circulation or reflux cooling and starting a RCP.

The licensee has also developed abnormal operating procedures that address loss the RHR support systems: AOP 3.2-10, Loss of Component Cooling Water; AOP 3.2-15, Loss of a Vital Bus; AOP 3.2-19, Loss of Service Water; and, AOP 3.2-25, Low Voltage on Emergency Busses.

c. Conclusions

The team concluded that the licensee had developed reasonable plans and procedures that should be able to cope with a loss of residual heat removal event.

O4 Operator Knowledge and Performance

O4.1 Reactor Coolant System Draindown

a. Inspection Scope

The inspection scope was to review operator actions during a pre-planned draining evolution of the RCS on August 29, 1996.

b. Observations/Findings

On August 29, 1996, during two separate occasions the control room operators aligned the RHR purification system and letdown the RCS to the ADT through valve WD-V-210.

At approximately 1609 after a total of approximately two hours of draining the RCS, the evolution was stopped due to an outage planning decision that postponed the reactor disassembly until September 3, 1996. The RCS draining evolution supported removal of the reactor vessel head.

Discussions with the US and the RO indicated that the total inventory change was estimated at 3,000 gallons. However, the second draindown evolution was stopped at 280 inches cavity level after approximately 4,000 gallons were drained to the ADT. (The licensee later calculated 4515 gallons as the total inventory change based on run time of the ADT pump.) The operators attributed the difference between the estimated draindown volume of 3,000 gallons and their ADT draindown of 4,000 gallons to in-leakage from the RCS loops. The operators manually closed in on RCS isolation valves for two loops and isolated the loop overpressure protection valves for all four loops. After this action, operators noted that cavity level continued to increase with no make-up but the rate of increase slowed after the valves were verified closed and the loop overpressure protection valves were closed. The next shift added approximately 1,000 gallons to the RCS and returned cavity level to its approximate initial value.

Based upon team interviews with the shift operators and operations management, the magnitude of the RCS inventory mismatch was not identified in an ACR, nor was it explained to operations management. Nor did the operators solicit E&TS to assist in resolving this discrepancy. The team asked the licensee for the history of loop stop valve leakage. The licensee has experienced leakage of the loop stop valves during past outages, however quantification of that leakage has not occurred. Based on the inventory imbalance, the team concluded that leakage of this magnitude could not have occurred through the closed loop stop isolation valves.

Further, the team learned that isolation of the loop overpressure check valves by the operators resulted in no overpressure protection for the RCS loops. The team evaluated the temperature changes in the loops, containment temperature, and the RHR suction temperature between August 29 at 1427 until August 30, 1996 at 0416, when the loop overpressure protection was isolated. The maximum recorded rise in loops temperatures was 3°F and the containment temperature decreased 3°F based upon the startup of the second containment air recirculation fan. The TS limit based upon heat up limitation curves of TS Figure 3.4-4 at the RCS temperature of approximately 80°F was approximately 480 psig. Licensee evaluation of the loop temperature variations indicated that this limit was not exceeded.

The team learned that the normal operating procedures to isolate an RCS loop did not require that the overpressure protection check valves be left in service, and the locked valve checklist for the isolation of the overpressure check valves required the valves to be opened in Operational Modes 1 through 4, but not cold shutdown.

c. Conclusions

Operators failed to inform management or engineering/technical support of the significance of the inventory balance given the insupportable magnitude of leakage from the loop stop isolation valves. The operators isolation of the loop overpressure protection valves was inappropriate in that it removed the only means to relieve an overpressure condition within the isolated loops. The normal operating procedures did not preserve the pressure protection of an isolated loop. The operators failed to display a questioning attitude in not investigating the cause of increasing RCS level indication with no makeup.

04.2 Return of the Reactor Coolant Loops to Service

a. Inspection Scope

On August 31, 1996, a small leak was identified on the "A" RHR heat exchanger inlet valve, RH-V-791A. The heat exchanger was isolated and the "A" loop of RHR was declared inoperable. On September 1, the operators performed NOP 2.4-7, Return of a Loop to Service with the Plant Shutdown, and unisolated the RCS loops to increase the predicted time to boiling in the RCS should the remaining RHR pump be lost. The team reviewed NOP 2.4-7 and discussed its performance with the cognizant operations US, SM and the Chemistry Department.

b. Observations and Findings

Procedure NOP 2.4-7 provides the detailed instructions necessary to return a RCS loop to service after it has been isolated or idled and requires that prior to opening the loop stop isolation valves, the isolated or idled loop shall be determined to have a boron concentration greater than or equal to the boron concentration required to meet the shutdown margin requirements of TS 3.1.1.4 and to have a cold leg temperature within 20 °F of the operating RHR loop. Prior to sampling the isolated

or idled loops for boron concentration and determining loop temperature, steps 6.2.2 and 6.4.3 of NOP 2.4-7 direct that the associated RCP be started in accordance with NOP 2.4-2, Reactor Coolant Pump Operation.

The US for the 0600 - 1800 shift on September 1 indicated that the procedure steps required for operation and start of a RCP in accordance with steps 6.2.2 and 6.4.3 of NOP 2.4-7 were not performed but marked as "N/A" since the loops were being returned to service for availability and decay heat removal concerns only, and the RCPs and plant were to remain shutdown. The US further indicated that the verification of adequate loop boron concentration was based on the sample results provided by the Chemistry Department where loop #1 boron was 2874 parts per million (ppm), loop #2 boron was 3111 ppm, loop # 3 boron was 1790 ppm, and loop #4 boron was 2235 ppm taken prior to opening the loop stop isolation valves and the last known loop boron concentrations of approximately 1400 ppm taken prior to loop isolation on August 12, 1996. The SM for the 1800-0600 shift on September 1 and 2 indicated that isolated loop temperatures were verified by contact thermometer readings on the secondary side steam generator hand hole covers and were within 20 °F of RHR temperature. Management review of completed procedure NOP 2.4-7 was completed on September 2, 1996, by the Operations Manager.

The team discussed the loop boron sample results with the Chemistry Department and reviewed the relevant records to determine whether the boron samples were properly obtained and if the results were credible. The chemists indicated that the loop boron sample results were not credible since the samples could not be obtained in accordance with approved procedures, i.e. the RCPs were not started and the loops were at atmospheric pressure resulting in the samples not being taken at the sample sink but being drawn locally in the containment off the loop drain header. The chemists further indicated the operators were advised that the results would not be valid indicators of loop boron concentration. When the boron samples for loops 1 and 2 indicated boron concentrations greater than the RHR system, the operators requested another sample and obtained similar results. The operators failed to follow-up the boron sample discrepancy with chemistry prior to unisolating the loops. The team reviewed the sample records and determined the approximate loop boron concentration prior to isolation was 1430 ppm boron and that no evolutions with the potential for dilution of loop boron concentration had occurred after loop isolation on August 12, 1996. The team verified in surveillance procedure (SUR) 5.3-19, Boration Requirements for Reactor Shutdown, and in the fuel cycle report that the required shutdown margin boron concentration in this condition was approximately 850 ppm.

The Procedure Compliance Policy of ACP 1.2-6.5 states that "... if the procedure appears to be inadequate for the intended task ... then task will be stopped" and limits the use of "N/A" for cases where a step or steps of a procedure are clearly not applicable. The lack of representative boron samples indicated a failure to comply with the intent of the procedure. Furthermore, the licensee identified on September 13, 1996, that the boron samples may not have been taken within 30 minutes of unisolating a loop as required by TS 4.1.11.2.

The team made the following observations regarding the licensee's performance of NOP 2.4-7:

- The operators use of "N/A" for action steps dealing with operation of the RCPs was improper and resulted in unrepresentative boron samples and isolated loop temperatures, and a failure to comply with TSs 4.4.1.11.2 and 4.4.1.11.1. The as-performed procedure was inadequate for these two tasks and should have been stopped until appropriate procedure changes were made or the RCP could be started.

- The safety consequence of the operators failure to obtain accurate loop boron and temperature results was minimal based on the loops' previous boron concentrations and ambient temperature conditions.

- The management review of the completed procedure was inadequate since it also failed to identify the procedural non-compliance.

c. Conclusions

The team concluded that NOP 2.4-7 was improperly performed. The licensee failed to ensure that isolated loop boron concentrations and loop temperatures were correctly determined prior to opening the loop stop isolation valves. Although not directly contributing to the occurrence, the management review of the completed procedure was inadequate since it also failed to identify the procedural non-compliance.

O4.3 Operator Implementation of Abnormal Operating Procedure for Reactor Coolant System Leakage Indication

a. Inspection Scope

The inspection scope was to evaluate operator response on September 1, 1996, to a unexpected reduction in RCS inventory.

b. Observations/Findings

On September 1, 1996, at approximately 0900, the NSO isolated nitrogen gas to the VCT while conducting an investigation into increased nitrogen use noted over the past four days. When nitrogen was isolated to the VCT, the RO noted a decrease in cavity level and pressurizer level. Based on interviews with the RO, the RCS leak rate was estimated at approximately 20 gpm. The SM directed the NSO to restore nitrogen slowly to the VCT and increase VCT nitrogen pressure at 5 psig increments from approximately 20 psig to 30 psig.

The US executed the action steps of AOP 3.2-31A, Reactor Coolant System/Refueling Cavity Leak (Mode 5 and 6), to identify and isolate the source(s) of the leak. The RO initiated makeup to the RCS using a suction path from the RWST through the "A" RHR pump. AOP 3.2-31A also requires a review of

Emergency Plan Implementing Procedure (EPIP) 1.5-1.A, Emergency Assessment, for determination of potential reportability, incident classification and initiation of emergency actions. Based on interviews, the SM stated that he consulted the EPIP and concluded that he did not meet the threshold provisions for an emergency classification declaration or the immediate notification criteria of 10 CFR 50.72. On September 11, 1996, the licensee reported the event under 10 CFR 50.72 (b)(2)(iii)(B).

The operators' leak investigation for areas both outside and inside the containment was completed by approximately 1015 and 1057, respectively. No potential leak sources were identified. However, based on the indicated pressurizer level decrease and the potential RCS inventory reduction, the SM directed the RO to control RCS inventory and by maintaining indicated pressurizer level between 5% to 15%. The licensee calculated that approximately 5,000 gallons of borated water were added to the RCS based on the change in RWST level.

During the RCS leak investigation, the operators had suspected nitrogen gas intrusion into the vessel as the cause for the cavity and pressurizer level changes. In parallel, with implementation of AOP 3.2-31A, the operators cycled and verified closed the two valves connecting the VCT gas space to the "B" charging pump suction header. Valves BA-V-354 and BA-V-355 were verified closed, and the nitrogen supply to the VCT was isolated. The above valves were tagged out at approximately 1353. This action isolated the nitrogen intrusion through the charging system into the RCS. At approximately 1255, on September 1, 1996, RCS inventory was stabilized and indicated pressurizer level returned to its approximate initial value of 10%.

The team reviewed the SM's logs and concluded that this record failed to adequately describe the sequence of events recounted above in that all of the major activities were summarized under a single log entry for 0900 on September 1, 1996. The operations crew initiated ACR 96-0966 to document this event and the actions taken. Based upon interviews, operations requested no additional support to evaluate the worst case inventory reduction within the reactor vessel given an apparent significant nitrogen gas displacement of reactor coolant. Three days later, the licensee performed a preliminary volumetric balance on September 4, 1996, and concluded that worst case inventory reduction within the vessel was 39 inches below the reactor vessel flange.

c. Conclusions

The team noted acceptable diagnosis and AOP implementation by the operators to identify potential RCS leakage source(s). After further review by the licensee staff, the SM's initial reportability decision of September 1 was reconsidered and the event was later reported by the licensee on September 11, 1996. Operations requested no additional technical support to evaluate the worst case inventory reduction within the reactor vessel given an apparent significant nitrogen gas displacement of reactor coolant.

O4.4 Placing Residual Heat Removal Purification System in Service

a. Inspection Scope

The inspection scope evaluated operator performance during a system alignment to restore RHR purification on August 22, 1996.

b. Observations/Findings

On August 22, 1996 a non-licensed NSO failed to adhere to NOP 2.7-4. Specifically, the operator failed to perform step 1.4 of NOP 2.7-4 which restores the system alignment from a temporary shutdown of the purification sub-system of RHR. Failure to perform the alignment resulted in maintaining valve PU-V-261A open. Valve PU-V-261A is the suction valve from the RWST to the purification pump. When the operator performed step 1.5 of NOP 2.7-4, it required opening valve RH-V-874A which is the outlet valve from the RHR heat exchangers to the suction of the purification pump. With this alignment, RHR flow, instead of being directed to the purification pump, was diverted to the RWST.

When directed to place the RHR purification back in service, the NSO assumed step 1.4 had been completed and restarted the temporary shutdown procedure at step 1.5 - "COMMENCE purification of the RHR System" - and opened valve RH-V-874A which diverted RHR flow to the RWST. On receipt of a cavity low level alarm in the control room, the RO, after consulting with the NSO, directed the NSO to shut valve RH-V-874A isolating the flowpath from the RHR system to the RWST. The consequence of skipping step 1.4 was the inadvertent diversion of approximately 500 gallons of RCS water from the RHR system to the RWST over a period of approximately five minutes.

Based upon interviews with the shift operators, the team noted that this was the first time the NSO had performed the procedure for restoration of RHR purification. The on-shift US indicated his expectation was that if the NSO had questions about the NOP implementation that they should be discussed prior to the evolution. The licensee's IRT found that no pre-job brief occurred prior to the restoration of RHR purification.

c. Conclusion

During the restoration of the RHR purification system alignment on August 22, the NSO failed to adhere to NOP 2.7-4. The licensee failed to conduct an adequate pre-job brief for the operator who was performing NOP 2.7-4 for the first time. The result of this lack of procedure adherence was the diversion of approximately 500 gallons of RCS water to the RWST.

O4.5 Improper Alignment of Boration Flowpath

a. Inspection Scope

The inspection scope was to evaluate the events and details associated with changing the boration flowpath on August 28, 1996.

b. Observations/Findings

On August 28, a NSO misaligned valves in the boric acid system which connected the VCT gas space to the suction of the charging system, through valves BA-V-355 and BA-V-354 and subsequently into the RCS. At the time, the VCT was pressurized with nitrogen gas to approximately 30 psig consistent with NOP 2.3-4 which allowed for a makeup flowpath to the RCS using VCT pressure. The RCS was approximately atmospheric pressure and vented to the reactor vessel vent header system. The boric acid system valve misalignment resulted in CVCS nitrogen and water being injected into the RCS. The pressurizer level increased approximately 2% and VCT pressure decreased approximately 2 psig.

Verification of another boration injection flowpath was required in preparation for an expected emergency diesel generator surveillance later in the day. The emergency diesel generator is considered inoperable during its surveillance test making the existing flowpath via the metering pump to the RCS also inoperable.

Based on interviews with the US, RO, work control supervisor, and the NSO on shift at the time of the event, the team concluded that the NSO received a less than adequate pre-job briefing. It was apparent that the NSO discussed various aspects of the task separately with all of aforementioned individuals but that an integrated pre-job brief, with clear expectations for task performance, was not conducted. Additionally, based upon interviews with the shift operators, the team noted that this was the first time the NSO had performed a boron injection flowpath verification using procedure SUR 5.1-159B.

As a result of an inadequate pre-job brief, the NSO chose a flowpath incompatible with the existing VCT status and valve line-up - approximately 30 psig nitrogen in the VCT and valves CH-MOV-257/257B blue tagged shut - and incorrectly opened BA-V-355. Opening this valve allowed the nitrogen pressure in the VCT to inject CVCS system water and nitrogen into the RCS. The RO's initial response to the boration flowpath error was to readjust the high alarm setpoint for cavity level and increase it by approximately 5 inches higher than actual level. On receipt of the second high cavity alarm, the RO directed the NSO to close mis-positioned valve BA-V-355 and stop performance of SUR 5.1-159B. The team learned that no specific procedural expectation exists for controlling the high level alarm setpoint for cavity level. (Annunciator Response Procedure (ANN) 4.24-1, Cavity High Level, indicates the setpoint is determined by the operator. NOP 2.3-4 and NOP 2.4-10, Reactor Coolant System Mid-Loop Operation, require the adjustment of the low level

alarm setpoint to 255.5 inches and 208 inches, respectively, prior to conducting RCS draindown evolutions.) The licensee estimates that the amount of inventory added to the RCS was 500 gallons, in addition to nitrogen. The licensee prepared ACR No. 96-0946 to document the event and to identify potential corrective actions.

c. Conclusions

During the evolution to shift boration flow paths, nitrogen gas entered into the RCS. The evolution to shift boration flow paths was inadequately performed, in that, the NSO, who lacked experience and familiarity with the job task, was given an inadequate pre-job brief by shift management.

O4.6 Failure to Control Maintenance Testing on Containment Spray Valves

a. Inspection Scope

The inspection scope was to evaluate operations performance during an inadvertent RCS draining evolution during maintenance testing of RHR motor-operated valves.

b. Observations/Findings

On September 4, 1996, between 200 to 300 gallons of reactor coolant was discharged to the containment sump from the RHR system. The leakage path was through a pair of motor-operated valves (RH-MOV-23 and RH-MOV-34) and a common isolation valve RH-V-23A to the containment spray automatic drain valve (RH-V-888). At the time, the licensee had a stop work order in effect on RHR and systems affecting RCS inventory.

A preventative maintenance activity was being performed to disassemble the two motor-operated valves (RH-MOV-23 and RH-MOV-34). In support of this disassembly the valves were moved off their closed seats. The RHR flow was diverted through the valves, and through a manual valve that was thought to have been closed (RH-V-23A) and then subsequently through valve (RH-V-888) to the containment sump.

The SM noted a small decrease in pressurizer and cavity level indication. An operator was dispatched to containment to locate the potential leakage. Approximately five minutes after the event started, operators reenergized the two motor-operated valves, closed the valves, and terminated the loss of RCS inventory. The leakage resulted in approximately 1.5% decrease in pressurizer level and approximately 5 inch decrease in cavity level. The operator in containment, closed RH-V-23A another 1/8 of a turn.

The maintenance should not have occurred as a result of the stop work order issued on September 2, 1996. This particular maintenance activity was not pulled by outage management, and the electrical maintenance department assumed that since it was acceptable to work, they proceeded on September 4, 1996. Additionally,

the team learned that the SM was not informed about the maintenance activity. The control room operators were aware of the activity, but felt that it was low risk since isolation valve RH-V-23A was closed. They assumed that the work was approved since the work control center and tagging office had cleared the work order.

c. Conclusions

The operations crew did not thoroughly question the decision to proceed with the work given a limited stop order work on systems involving RHR and other primary systems affecting RCS inventory. The team determined that the operator response to the reduction in RCS inventory was appropriate.

O4.7 Operator Response To Excessive Liquid Nitrogen Use

a. Inspection Scope

The inspection focused on the operator sensitivity to liquid nitrogen use during an outage.

b. Observations/Findings

Based upon the team's interviews with a variety of operators, it was concluded that their concern for high levels of liquid nitrogen usage during the outage was only a function of the need to resupply the tanks. In general, the operators were aware of past large demands for nitrogen to support outage activities such as a steam generator sparge or draindown. The NSO's logs require recording nitrogen tank level every eight hours. At 20 inches in the tank it recommends actions be taken to refill the tank.

During the period of August 29 until September 1, 1996, the use of nitrogen by the facility had dramatically increased from the trend prior to August 29, 1996. Prior demand for liquid nitrogen resulted in an approximate three inch tank level decrease over 24 hours. Between August 29 through September 1, 1996, the liquid nitrogen tank level decreased on average 15 inches per day. One use of nitrogen during this time frame was the draindown and refill of the No. 2 steam generator.

On September 1, 1996, the shift NSO raised to the US the significant increasing trend in nitrogen usage since the tanks had just been filled on August 29, 1996. Based upon the NSO's concern, the US coordinated a systematic search for excessive nitrogen use by plant equipment. The troubleshooting process involved the US using the P&ID for the nitrogen system, and coordinating with the NSO to isolate and unisolate various loads. Plant operators failed to solicit help from E&TS to locate the source of the nitrogen gas leakage.

At approximately 9:00 a.m., the NSO isolated the nitrogen supply to the VCT. The NSO noted that primary auxiliary building nitrogen pressure increased from 40 psig to 63 psig, and VCT pressure decreased from 29 psig to 18.5 psig. The control room also noted a corresponding decrease in cavity and pressurizer level. The control room personnel felt that they had a RCS leak and entered AOP 3.2-31A. On entry into AOP 3.2-31A, the SM told the NSO to unisolate the nitrogen supply to the VCT. Based upon team interviews, the SM felt it was prudent to place the system back in its normal configuration, and perform actions of AOP 3.2-31A.

On September 1, 1996, operations management developed ODI-190 to, in part, maintain an inventory of liquid nitrogen on-site and log its usage for monitoring of abnormal trends. On September 11, 1996, the team confirmed implementation of the instruction.

c. Conclusions

In general, operators were knowledgeable of historically known large liquid nitrogen loads during refueling outages, however they lacked a timely questioning attitude for the unexpected nitrogen usage between August 29 until September 1. The team concluded that the operations and E&TS staff were not timely in investigating the source of the high nitrogen gas usage.

O4.8 Event Notifications

a. Inspection Scope

The team reviewed the event notifications, made by plant operators to the NRC, to verify that the notifications were completed in accordance with NRC requirements.

b. Observation/Findings

Prior to the arrival on site of the NRC inspection team the licensee had made one report in accordance with the requirements of 10 CFR 50.72 concerning the through-wall leak in an RHR system valve. There were no events classified under their emergency plan.

The licensee reported discovery of a through wall leak in the "A" RHR heat exchanger inlet isolation valve in accordance with 10 CFR 50.72(b)(2)(i) at 13:52 on August 31 (Event No. 30945). However, the licensee had not reported the potential loss of RHR caused by the accumulation of nitrogen in the reactor vessel before this concern was identified by the team. The licensee reported this event in accordance with 10 CFR 50.72(b)(2)(iii)(B) at 15:04 on September 11 (Event No. 30992).

The inspection team reviewed the classification of events that were the subject of this inspection in regard to the station emergency plan. EPIP 1.5-1, Emergency Assessment Using EAL Tables, addresses this classification procedure. None of the events required emergency classification.

c. Conclusions

On September 1, 1996, the licensee failed to report the event that could have prevented the fulfillment of the safety systems that are needed to remove residual heat within four hours as required by 10 CFR 50.72(b)(2)(iii)(B). The team concluded that the accumulation of nitrogen gas in the reactor vessel could have prevented the RHR system from functioning. The proper notification was made by the licensee to the NRC on September 11, 1996.

O5 Operator Training and Qualifications

O5.1 Level Indication and Vent Header System Training During Mode 5 Shutdown Conditions

a. Inspection Scope

The team reviewed the licensed and non-licensed operator training material regarding operation of RCS level instrumentation and the reactor vessel vent header systems during cold shutdown conditions, and interviewed several operators and a training department representative with respect to their content.

b. Observations and Findings

The team reviewed the Refueling Malfunctions lesson plan (CY-OP-LO-AOP-L11), the Mid-Loop Operations lesson plan (CY-OP-LO-NOP-L10), and the Fuel Handling lesson plan (CY-OP-LO-PRISYS-L00900) and discussed their content with a licensee training department representative. The training representative indicated these lessons are used in the initial and continuing licensed operator training programs to cover RCS level instrumentation operation and industry events. The lessons provide a description of the RCS level indications, controls, and alarms available during shutdown and refueling conditions. The lessons mandate review for two events - reactor seal cavity failure event (NRC IN 84-93) and undetected accumulation of gas in reactor coolant system (NRC IN 94-36). However, the lessons provide no detailed information on RCS level instrumentation operation and its response for mode 5 operations or the effects that reactor vessel vent header operation or other system changes can have on level indication. The team confirmed this observation during interviews with several operators who indicated that existing training material does not present detailed information regarding RCS level instrumentation or reactor vessel vent header operation for the irregular conditions existing with the plant in cold shutdown.

The team reviewed the licensee's continuing training schedule for the previous and current periods. The training representative indicated that presentation of the information discussed above was planned for August and September 1996 during Licensed Operator Requalification Training (LORT) Cycle 96-5 but was postponed until the week of September 30 due to the early plant shutdown. He indicated that this information was last presented to licensed operators during LORT Cycle 94-6 in October and November 1994. In lieu of LORT Cycle 96-5 training, originally

scheduled for one week, the licensee substituted one day of training prior to the outage on selected refueling topics that focused on various refueling evolutions, loss of RHR and AC events, and containment closure TS requirements. This training did not discuss RCS level instrumentation or reactor vessel vent header operation.

Finally, the training representative indicated the current training information provided on the reactor vessel vent header system does not discuss system operation and is limited to a description of the system's connection points to the RCS (lesson CY-OP-NLO-PRISYS-L00210). Updated training information for this system is planned for development and presentation in LORT Cycle 6 beginning the week of September 30.

c. Conclusions

The team concluded that the quality of existing training information for operation of RCS level indication and the vent header system during cold shutdown conditions was weak and failed to provide any substantial information on their operation during the irregular conditions existing with the plant in cold shutdown. The licensee failed to provide the scheduled detailed training on outage and refueling operations due to the early plant shutdown. The team determined that the failure to conduct this training was a contributing cause for this event.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Timeliness of RHR Pump Replacement

a. Inspection Scope

The team reviewed the maintenance activities to repair the "B" RHR pump.

b. Observations and Findings

On September 2, 1996, the maintenance mechanics began a disassembly and inspection of the spare RHR pump. The inspection was performed to verify that the spare pump was in compliance with the pump manufacturers specifications. By September 4, 1996, the maintenance mechanics had identified that the spare pump had several out-of-tolerance dimensional readings that would require corrective action by the pump vendor. The specific out-of-tolerance readings were the concentricity and perpendicularity between the bearing and head casings. The head casing and the pump impeller also required additional machining and balancing. The pump casing was returned to the pump vendor for machining on September 8, 1996, and the impeller was returned the following day. The spare pump, casing wear rings, and new vent valves were not available for installation until September 13, 1996.

The team noted that the lack of vendor information on the pump resulted in delays during the pump inspection activities. The licensee had to request the specifications from the vendor. Certain pump drawings were not received from the vendor until September 7, 1996.

On September 15, 1996, the post maintenance test of the "B" RHR pump failed due to inadequate pump venting and vent locations. The second post maintenance test also failed on September 16, 1996, when operators observed low oil level in the bearing housing and the pump was secured. On September 16, 1996, the maintenance staff identified two through-wall cracks on the motor upper end bell. This caused further delay while an analysis of the motor was performed. The post maintenance testing of the pump resumed on September 21, 1996, at which time oil leakage was noted near the pump thrust bearing. The oil leakage was caused by the slip of an oil seal baffle that had an improper interference fit. The first attempt to repair the oil seal baffle was unsuccessful and additional repairs were required. The RHR pump was returned to operable status on September 25, 1996, 25 days after the pump was identified as having failed.

c. Conclusions

The team determined that repair activities for the RHR pump were generally methodical and conservative. However, several avoidable delays resulted in the untimely restoration of the pump to service.

M1.2 Removal and Replacement of the "B" RHR pump

a. Inspection Scope

The team observed the removal and replacement of PAB access floor blocks and the "B" RHR pump repair to assess the licensees maintenance practices.

b. Observations and Findings

On September 4, 1996, the PAB floor blocks were removed. The team noted that the pre-job briefing for the removal of the floor blocks was thorough. The floor blocks were removed in accordance with WCM 2.2-7, PAB/Pipe Trench Floor Block Lift Procedure. The team noted that step 1.3, which required the floor blocks to be sealed with a silicone rubber adhesive upon reinstallation, was not completed. The system engineer was not aware of this step and had not taken this into account during the development of the engineering evaluation for the removal of the floor blocks. The licensee posted a flood/fire watch until further engineering evaluations were performed.

Corrective Maintenance Procedure (CMP) 8.5-99, Residual Heat Removal Pump Maintenance, step 6.2.11, requires the installation of a foreign material exclusion (FME) cover over the "B" RHR pump discharge case opening, and step 6.2.12 requires a Quality Assessment Services inspector to verify the work is performed. During a walk-through of the RHR cubicle, the team observed an appropriate FME

cover on the pump case; however, the pump casing drain line and the seal water heat exchanger lines were not taped off for FME control. The team discussed this issue with the maintenance manager and was informed that this discrepancy did not meet management expectations. The proper FME covers were installed.

c. Conclusions

The team concluded that the maintenance activities were generally performed according to the appropriate procedures; however, the team noted a few examples where procedure requirements were not adequately implemented.

M2 Material Condition of Facilities and Equipment

M2.1 Material Condition of the RCS Vent Header & Isolation Valves

a. Inspection Scope

On September 3, 1996, members of the team walked down the reactor coolant vent header system with a reactor operator. The purpose of the system walkdown was to verify system alignment and configuration as described in the operating procedure. The team also assessed the material condition of equipment associated with these events.

b. Observations/Findings

The reactor coolant vent system is a temporary system that is installed during cold shutdown conditions. The purpose of the system is to remove gases from the RCS. The controls for installation and operation of the system are identified in NOP 2.9-6. The system is not described in the UFSAR, and there are no license requirements for its operability. The vent system is connected to the RCS loops, pressurizer, pressure relief tank, and the reactor vessel head.

The team identified various equipment and procedural deficiencies during the system walkdown. Hardware deficiencies included kinked tygon tubes, lack of an adequate level in the moisture drain tank and condensate in the reactor head vent hose.

The team noted several valves in the CVCS and RHR that failed to perform there isolation function. The leaking CVCS valves allowed nitrogen gas to enter the RCS. Leaking RHR valves allowed water from the RCS to be diverted into the containment sump.

c. Conclusions

The temporary reactor coolant vent system was in poor material condition as observed by the team on September 3, 1996. The team noted that a series of leaking isolation valves were the root cause for two of the events reviewed. The team concluded that based on the large number of valves that leaked, that this may be a broader problem that requires additional attention.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Technical Response to the Accumulation of Nitrogen Gas in the Reactor Vessel

a. Inspection Scope

The team assessed the licensee's response to the identification of nitrogen gas in the reactor vessel.

b. Observation/Findings

The E&TS organization was not involved in identifying the source of the excessive nitrogen gas usage or evaluating the cause for the increase in pressurizer and cavity level indications. The E&TS staff were also unaware of the system configuration changes that allowed inappropriate maintenance to be performed on the RHR spray valves and the inappropriate closure of the RCS loop stop relief valves.

Following the identification of nitrogen gas in the reactor vessel on September 1, 1996, the licensee was unable to verify that all the nitrogen gas had been removed or that the reactor vessel was full of water. The E&TS staff initiated several actions to verify the actual reactor vessel level. Plant I&C technicians obtained local RVLIS and CET readings on September 3, 1996. The local RVLIS and CET readings were taken using available test equipment and existing procedures. The readings indicated that the reactor vessel was nearly full. A special test was necessary to positively verify that the vessel was full.

The E&TS organization developed two special test procedures to determine reactor vessel level and to verify that the reactor head vent was not blocked. The tests were completed on September 5, 1996. The test determined that the reactor vessel was not completely full and refilled the vessel.

On September 4, 1996, a temporary modification was installed to connect three CETs to provide indication in the control room. The RVLIS control room indication was restored, using a jumper, on September 11, 1996.

The shift manager had requested that the Shift Manager's Staff Assistant (SMSA) determine the worst-case (lowest) reactor vessel level that occurred during this event. The SMSA acquired background information, but did not determine a minimum reactor vessel level. On September 3, 1996, the Operations Manager initiated actions to perform this calculation. A preliminary analysis was completed on September 4, 1996. At the conclusion of the onsite inspection activities, the licensee had yet to complete a final volumetric inventory balance calculation.

c. Conclusions

The E&TS organization was not proactive in identifying and resolving several important technical anomalies that contributed to these events. The team concluded that a communications failure between operators and E&TS was a contributing cause for several of the events reviewed.

The initial actions taken by shift personnel, to refill the reactor vessel and the CVCS, were appropriate following discovery of nitrogen gas in the RCS. However, this initial corrective action was treated as a success without fully evaluating the overall safety implications.

The team concluded that the E&TS response to this event was not commensurate with its safety significance. The E&TS organization failed to take prompt action to obtain RVLIS measurements or verify the actual reactor vessel level. The team noted that confusion among plant staff on the ability to collect this information contributed to this delay. The reinstallation of the control room CET and RVLIS indications was not completed in a timely manner. The special tests, to verify reactor vessel level and vent header operation, were also delayed.

E2.2 Technical Response to the RHR Pump Failure

a. Inspection Scope

The team assessed the licensee's response to the failed "B" RHR pump.

b. Observation/Findings

The RCS loop stop valves were opened to allow the steam generators to be a backup heat removal source, if the operating RHR pump was to fail. The operators opened the RCS loop stop valves at 2124, on September 1, 1996, about seven hours after the "B" RHR pump was identified as having failed. By the evening of September 2, the electric auxiliary feedwater pump was verified lined up to feed the steam generators from the demineralized water storage tank (DWST); the RCS integrity and modified containment integrity were verified; the AOP for loss of RHR was reviewed, and the nitrogen banks were isolated.

A RCP could be used to provide forced circulation of the RCS in the event the RHR system was unavailable. The RCPs could also be used to fill the steam generator U-tubes if nitrogen gas accumulates in the steam generators. A RCP and associated support systems were aligned for service on September 3, 1996.

On September 7, 1996, a personnel barrier was in place to control access around the operating RHR pump. At the same time, operator rounds in the RHR pump area were increased from every eight to every six hours.

c. Conclusions

Following the failure of the RHR pump, the operations staff appropriately focused their efforts on aligning a steam generator for natural circulation. The team concluded that actions were not timely for restoring a RCP to standby service.

The team concluded that the actions taken to monitor the operating RHR pump were not timely or comprehensive. The licensee appropriately provided a personnel barrier to limit access around the operating RHR pump. However, the team concluded that a non-intrusive pump performance monitoring surveillance should have been performed to provide assurance of proper pump operation. The "B" RHR pump was found to have significant thermal damage in area of the pump seals, yet no attempt was made to measure the operating pump's seal inlet and outlet temperatures.

E2.3 Technical Response to the RHR Heat E :changer Valve Leak

a. Inspection Scope

The team assessed the licensee's resp onse to the "A" RHR heat exchanger inlet valve leak.

b. Observation/Findings

On September 1, 1996, the RHR syste m engineer was on-shift as the SMSA. The operations crew requested SMSA input on the design limitations of flow through the RHR heat exchanger. The request was based upon maintaining RCS temperature, during an abnormal alignment of the RHR system, with only one of two heat exchangers. The applicable procedure, NOP 2.9-1, did not provide limitations on RHR flows or guidance on the alignment of the RHR system with one heat exchanger. The SMSA provided guidance to the crew on flows to limit RHR pump "run-out", and maximum flow rate through a heat exchanger based on design values identified in vendor information. The crew implemented this guidance on flowrates during the evolution to remove the "A" RHR heat exchanger from service. The SMSA guidance was subsequently incorporated into revision 31 to NOP 2.9-1.

The RCS system engineer supported the operations crew by evaluating the location of the valve body leak on RH-V-791A, and provided recommendations to isolate the leak. The system engineer recommended closure of the valve, since the defect was located on the valve body, whereas the valve disc would isolate RHR system pressure to the leak. Operators subsequently isolated the "A" RHR heat exchanger based upon the system engineer's recommendation.

The licensee completed several actions following discovery of the defect in the RHR heat exchanger inlet isolation valve, RH-V-791A, on August 31, 1996. For example, operators shut the leaking valve as a precaution to protect the RHR system integrity, because little was known about the extent of the flaw or the risk that it presented to the RHR system pressure boundary. An early decision was made to radiograph the valve. Although a contract radiographer arrived on site with a radiograph source that evening, the radiography was delayed pending an evaluation of the issues concerning rigging the 600 pound source container into the "A" heat exchanger cubical.

c. Conclusions

The licensee acted decisively following discovery of a through wall leak in the "A" RHR heat exchanger inlet valve. The E&TS staff promptly addressed the decay heat removal and system integrity issues. The actions taken in response to the leak identified on the "A" RHR heat exchanger inlet valve body were appropriate.

E2.4 Review of Generic Information

a. Inspection Scope

The team assessed the licensee's corrective actions taken in response to industry information on nitrogen gas intrusions into the RCS.

b. Observations/Findings

NRC Information Notice (IN) 94-36, Undetected Accumulation of Gas in Reactor Coolant System, describes an event at another nuclear power plant where nitrogen gas accumulated in the reactor vessel. The E&TS staff documented an evaluation of this IN in a letter (ODM 94-134, dated July 23, 1994). This evaluation stated a nitrogen gas bubble in the reactor vessel could cause a level decrease to four inches above the RCS hot leg center-line. The evaluation assumed that at this level the nitrogen gas could pass through the pressurizer surge line to the pressurizer and be vented to the vent header.

The recommendations documented in this evaluation were to maintain the RCS pressurized in cold shutdown when feasible and to isolate the VCT if the RCS is depressurized. If the VCT cannot be isolated, the evaluation specified that (1) the reactor vessel head should be vented to the vent header; (2) to maintain at least one channel of RVLIS available; and (3) to monitor the cold calibrated pressurizer

level for indications of a gas void in the vessel. The analysis explains that a gas void formation in the vessel would result in an increasing level in the pressurizer. The evaluation also recommended revising procedures to included indication of gas accumulation in the reactor vessel.

c. Conclusions

The team concluded that the E&TS staff conducted a thorough evaluation of the NRC IN. However, the recommendation to maintain one channel of RVLIS available was not implemented. The recommendation to revise procedures was narrowly focused and did not provide guidance in the procedures used during this event. The team determined that the failure to implement actions based on this evaluation was a contributing cause for this event.

E2.5 Outage Planning and Scheduling

a. Inspection Scope

The team reviewed the process for incorporating risk considerations in planning and control of outage activities.

b. Observations/Findings

The licensee has established Work Control Manual (WCM) procedure 1.2-9, Outage Planning, Scheduling, and Implementation, to provide the administrative controls to manage shutdown risk. The concept of designating system out-of-service windows was selected as the planning control mechanism. The licensee has also developed planning schedules for the current outage, Refueling Outage 19, that define the scheduled windows for systems. The shutdown risk profile shows a significant increase in relative risk during reactor disassembly until the reactor cavity is flooded. Therefore, during the events reviewed by the team, the shutdown risk profile indicates a relatively higher risk.

The licensee failed to apply appropriate controls to work that resulted in a diversion of water from the RCS. This event resulted while working on motor-operated containment spray valves on September 4, 1996. The activity was performed without the refueling water cavity filled and without contingency planning. This was contrary to WCM 1.2-9, Outage Planning, Scheduling and Implementation, Section 1.2.7.b, which states that activities which impact the RHR system should be scheduled during periods of low decay heat, maximum coolant inventory or defueled conditions. The containment spray valve work was inappropriately authorized after the RHR pump had been found failed.

Plant management made a decision on August 29, 1996, to postpone refueling outage maintenance activities over the 3-day weekend. A contractual obligation granted the personnel supporting the reactor disassembly a day off on Sunday, September 1. This outage period has a high relative risk. The licensee decision to delay the reactor disassembly process before opening seal connections on the

reactor head was conservative. When RCS integrity is not maintained risk increases because the steam generators are unavailable for decay heat removal. However, the licensee failed to fully evaluate the reactor status or take compensatory measures during the time that refueling activities were delayed. All four steam generators were isolated from the reactor vessel and the RVLIS and CETs were disconnected. There was no evaluation of the risk presented by this configuration and there was no contingency planning made for obtaining RVLIS or CET data.

The licensee's letter, dated June 15, 1992, provides CYs response to NRC Generic Letter (GL) 88-17, Loss of Decay Heat Removal. In that letter CY committed to having at least two independent temperature measurements, representative of the core exit, whenever the reactor vessel head is in place. Failure to connect the CETs deviated from this commitment.

c. Conclusions

The licensee has developed an appropriate work control procedure to minimize shutdown risk. However, certain decisions, such as, postponing the maintenance activities over the weekend without reactor vessel indications, were not thoroughly reviewed for risk significance. In this case, the reactor water level was lowered and the vessel isolated from all four RCS loops for an extended period, while the vessel temperature and level instruments were disconnected. The team concluded that while detailed guidance existed for minimizing shutdown risk, the implementation of the guidance was not adequate. It appears that the decision not to connect the CETs was not consistent with the licensee's GL 88-17 response.

E2.6 Reactor Coolant Vent System

a. Inspection Scope

The team assessed the quality of E&TS provided to install and operate the temporarily reactor coolant vent header system. The quality of the vent system normal operating procedure was evaluated in report section O3.2, operator training was evaluated in report section O5.1, and the material condition of the vent header was evaluated in report section M2.1.

b. Observations/Findings

The team learned through interviews with various operators, that on at least two occasions, operators requested engineering support to improve the temporary vent system. Licensee management did not initiate engineering activities to improve the system, primarily due to the priority of other engineering work requests, or a lack of a viable engineering solution.

The team noted that very limited engineering support existed for the temporary vent system. The system was controlled under NOP 2.9-6; however, no accurate drawings depicted the system alignment, nor were there any engineered design limitations on the capability of the system. Additionally, the team learned that no

material specifications existed for either the valves or hoses, or any guidance on proper installation of the temporary hoses. The licensee improved the control of the system and provided technical guidance on design limits for the system in a procedural revision to NOP 2.9-6 on September 14, 1996.

c. Conclusions

The team concluded less than adequate engineering support was evident in the design, installation, and monitoring of the temporary vent system.

E2.7 Root Cause Determination of the Failure of the "B" RHR Pump

a. Inspection Scope

The team reviewed the root cause failure analysis for the "B" RHR pump.

b. Observations and Findings

The licensee determined that the following four factors contributed to the failure of the "B" RHR pump: (1) the pump shaft deflection reduced the clearance between the shaft and the throttle bushing; (2) the 316 stainless steel throttle bushing did not have good wear properties relative to the 316 stainless steel shaft sleeve. This led to galling of the throttle bushing when the bushing was allowed to contact the shaft sleeve; (3) the out of round casing wear ring, the looseness of the head to casing fit, and the eccentricity of the head to casing fit resulted in a reduction in wear ring clearances, which allowed the shaft to contact some sections of the throttle bushing before the wear rings contacted; (4) the manufacturer specified clearances in the wear rings and the throttle bushing areas did not provide sufficient margin to prevent contact between the wear rings and between the throttle bushing and shaft sleeve.

The root cause for the pump failure was a combination of a marginal design and manufacturing defects. The combination of these manufacturing deficiencies led to the occasional contact of the shaft with the stationary throttle bushing. The stationary throttle bushing was located at the impeller end of the shaft. The occasional contact apparently broke tack welds that held the bushing in place. Once the tack welds were broken, the bushing was free to move along the pump shaft. The bushing may have caused the increase in vibration levels observed during the September 29, 1996, inservice pump test. The bushing eventually cocked and locked between the stuffing box bore and the shaft sleeve. This apparently occurred during a 45 minute pump run on August 19, 1996. The locked bushing cut the shaft sleeve, and heated the shaft leading to severe bowing and additional shaft rubs. The rotor seized when the pump was stopped. The "A" RHR pump, rebuilt in 1990, eliminated several manufacturing defects, similar to the ones found on the "B" pump in 1996. The licensee plans to inspect the "A" RHR pump, prior to entering mode 4 operation.

c. Conclusions

The team concluded that the licensee's root cause analysis was acceptable. While this root cause evaluation did not positively identify a root cause for this failure, a reasonable apparent cause was identified.

E7 Quality Assurance in Engineering Activities

E7.1 Independent Event Review

a. Inspection Scope

The team reviewed the licensee's independent event review response.

b. Observations/Findings

The licensee established root cause investigation teams for the RHR pump failure and the leaking RHR isolation valve on September 2, 1996. These investigation teams were later disbanded when an IRT was formed. Licensee senior management directed that an IRT be established on September 3, 1996. The IRT was functioning with 9 of 14 members on September 4, 1994. The IRT was to provide an independent assessment of the events and to determine the root cause for each event.

c. Conclusions

The team concluded that plant management's failure to fully appreciate the significance of this event resulted in a poor event response and in delays in initiating an integrated event recovery plan.

The team also concluded that the licensee was slow in developing a functional IRT. The IRT investigation was not completed at the conclusion of the AIT onsite inspection activities. Therefore, the quality of the IRT's assessment was not reviewed.

E7.2 Management Oversight Summary

Management oversight of the nitrogen bubble event and the degraded RHR system was fragmented and protracted, resulting in untimely corrective actions for significant conditions adverse to quality. The untimely response was reflected in (1) the failure to fully appreciate the significance of the event; (2) the delays to establish actual reactor level; (3) the delays to reestablish control room reactor vessel level and temperature indications; (4) the delays in aligning a reactor coolant pump for service; (5) the untimeliness of actions taken to monitor the operating RHR pump following the "B" RHR pump failure; and (6) the delays to establish and implement an independent review team.

V. Management Meetings

X1 Exit Meeting Summary

The team presented the inspection results to members of licensee management at the conclusion of the inspection on October 2, 1996. The exit meeting was open for public observation. The slides used at the exit meeting are provided as Attachment 2 to this report. The licensee acknowledged the findings presented.

No proprietary material was knowingly retained by the team or disclosed in this inspection report.

PARTIAL LIST OF PERSONS CONTACTED

Mike Baca, Operations Unit Supervisor
Lee Blaede, Operations Work Control Supervisor
Rick Borg, Supervisor of Information Technology
Gary Bouchard, Director of Work Services
Jonathan Bower, Operations Shift Manager
Will Chestnut, Operations Unit Supervisor
John Calderone, System Engineering
Sean Doody, Operations Nuclear System Operator
Gerry Dreschler, IRT Member
Joseph Eldridge, Nuclear System Operator
John Ferguson, Manager of Internal Review
Jeff Folden, Operations Unit Supervisor
Jim Hawxhurst, IRT Member
Mike Hess, IRT Member
Steve Hutton, System Engineering
Don Kidder, IRT Member
Dave Lazerony, IRT Member
Pierre L'Heureux, IRT Team Leader
John Majewski, System Engineering
Mike Marino, System Engineering
Clark Maxson, IRT Member
Roger McBeth, Nuclear Training
Doug McCracken, Acting Operations Manager
Pat Motes, Nuclear System Operator
Buster Orf, Nuclear System Operator
John Pointkowski, Operations Shift Manager
Phil Rainha, Operations Shift Manager
Chuck Reid, Operations Reactor Operator
Bill Rein, System Engineering
Jack Stanford, Start-Up Issues Manager
Larry Wellbrock, Operations Reactor Operator
Marty Williams, IRT Member
Dick Willis, Operations Shift Manager
Neil Young, Nuclear Training

LIST OF ACRONYMS USED

AOP	Abnormal Operating Procedure
ACP	Administrative Control Procedure
ACR	Adverse Condition Report
ADT	Aerated Drains Tank
ANN	Annunciator Procedure
BAMT	Boric Acid Makeup Tank
CFR	Code of Federal Regulations
CET	Core Exit Thermocouples

CMP	Corrective Maintenance Procedure
CVCS	Chemical and Volume Control System
CY	Connecticut Yankee
EG	Emergency Generator
EDG	Emergency Diesel Generator
EPIP	Emergency Plant Implementing Procedure
E&TS	Engineering and Technical Support
°F	Degrees Fahrenheit
FME	Foreign Material Exclusion
gpm	gallons per minute
HPSI	High Pressure Safety Injection
IN	Information Notice
IRT	Independent Review Team
I&C	Instrument and Control
kV	KiloVolts
LORT	Licensed Operator Requalification Training
LPSI	Low Pressure Safety Injection
N/A	Not Applicable
NOP	Normal Operating Procedure
NRC	Nuclear Regulatory Commission
NSO	Nuclear System Operator
ODI	Operations Department Instruction
Psig	Pound per square inch gage
P&ID	Piping and Instrument Drawing
PAB	Primary Auxiliary Building
PORC	Plant Operations Review Committee
PM	Preventive Maintenance
PMP	Preventative Maintenance Procedure
ppm	parts per million
RO	Reactor Operator
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RVLIS	Reactor Vessel Level Indication System
RWST	Refueling Water Storage Tank
SI	Safety Injection
SM	Shift Manager
SMSA	Shift Manager's Staff Assistant
SUR	Surveillance Procedure
TPC	Temporary Procedure Change
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
US	Unit Supervisor
WCM	Work Control Manual
VCT	Volume Control Tank

Figure 1

The Undetected Nitrogen Gas
Introduction into the
Reactor Vessel from the Charging Line

‚HE UNDETECTED NITROGE.. GAS INTRODUCTION INTO THE REACTOR VESSEL FROM THE CHARGING LINE

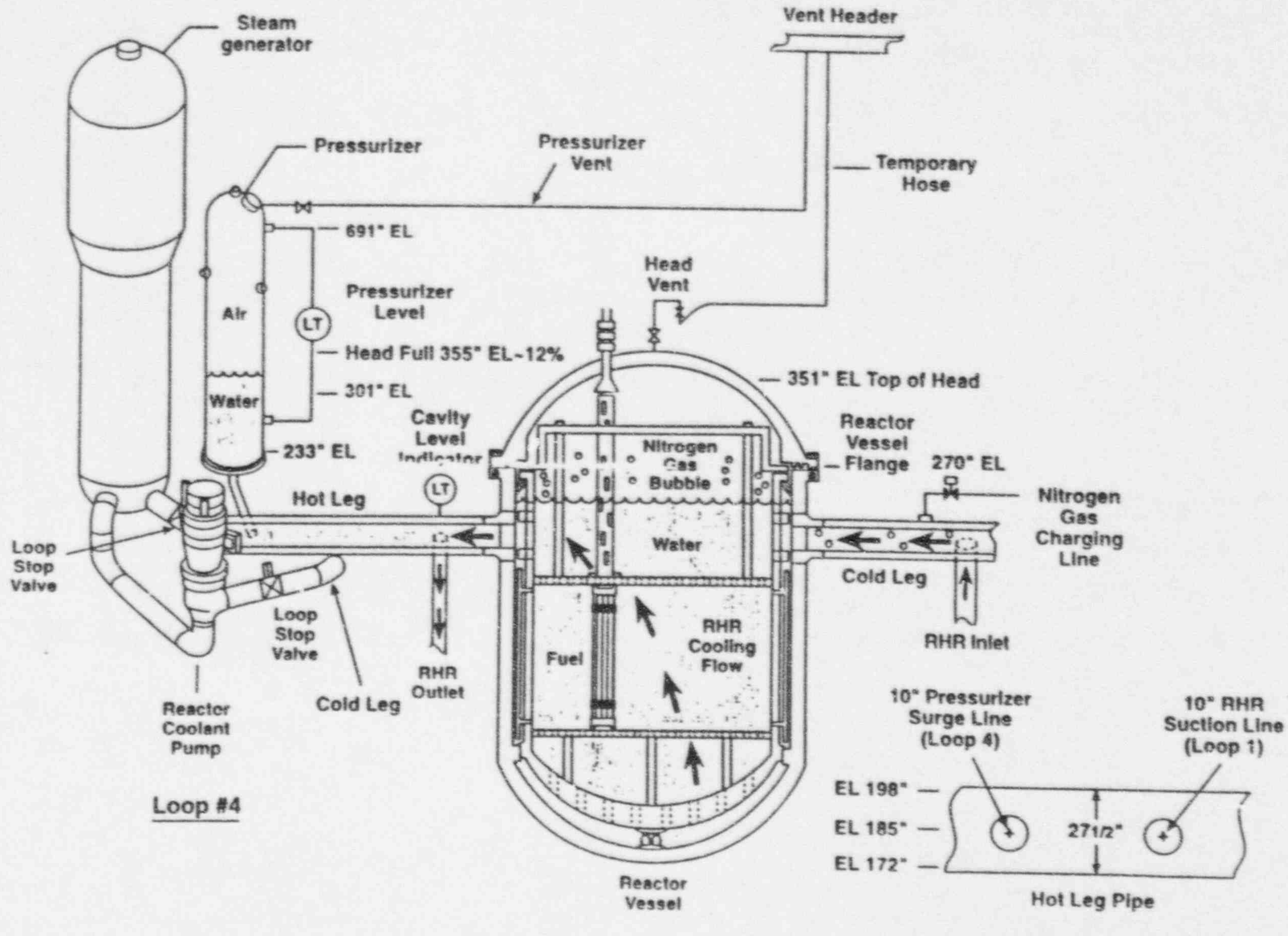

FIGURE 1

Figure 2

Chemical & Volume Control System

CHEMICAL & VOLUME CONTROL SYSTEM

NITROGEN GAS LEAK PATH FROM VOLUME CONTROL TANK TO THE RCS

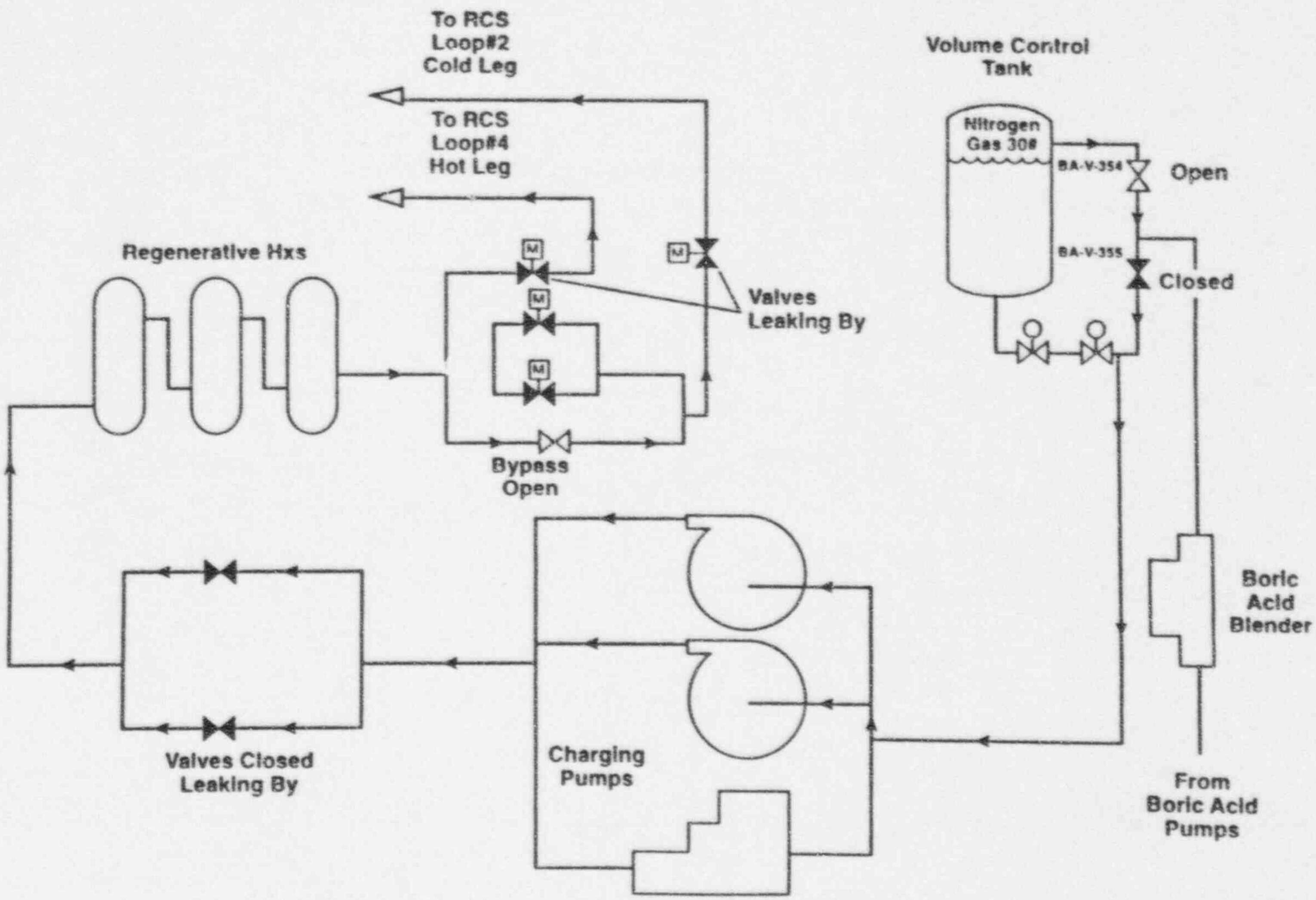

FIGURE 2

Figure 3

Residual Heat Removal System (RHR)

RESIDUAL HEAT REMOVAL SYSTEM (RHR)

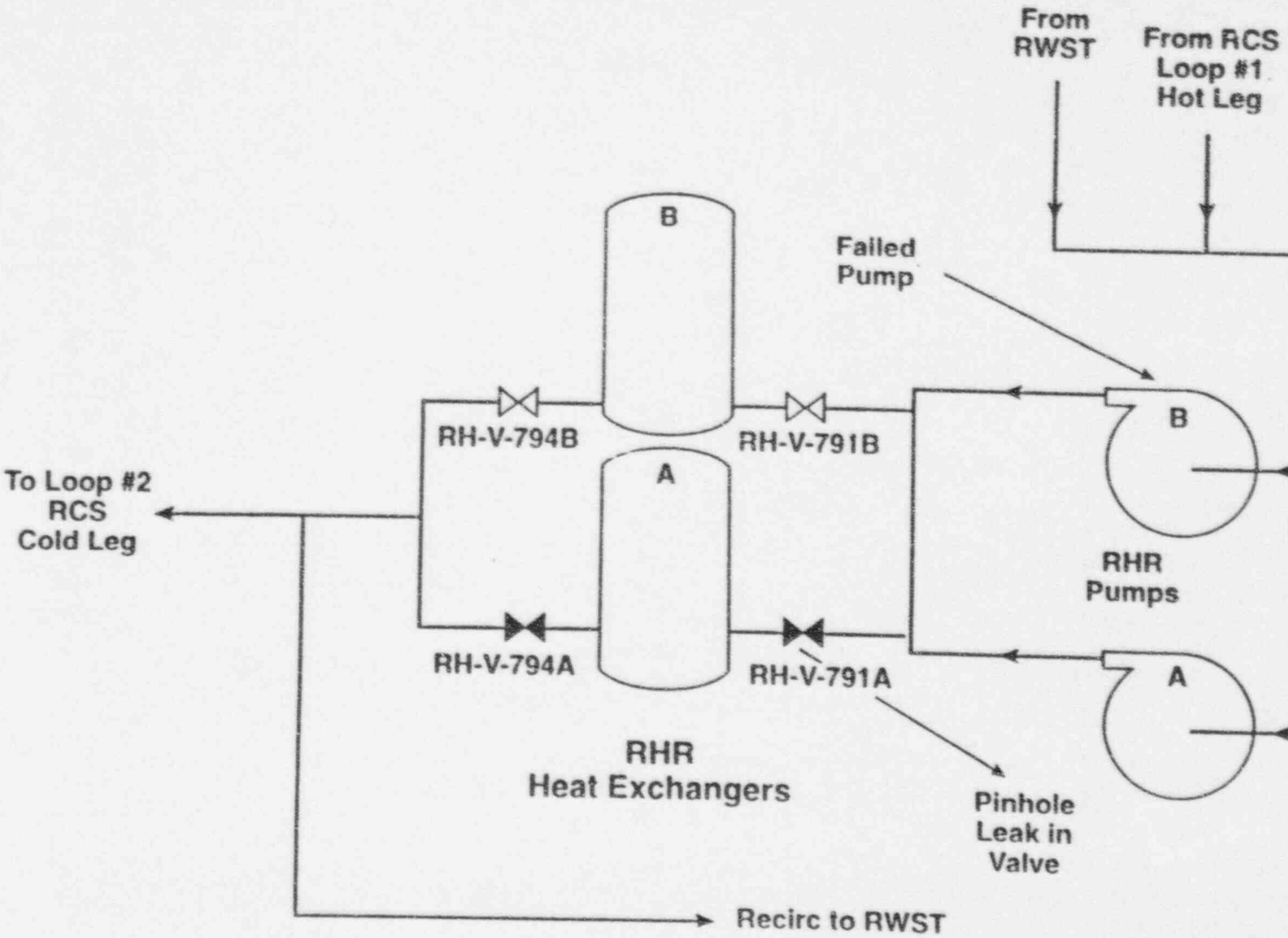

FIGURE 3

Attachment 1

AIT Charter

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

September 4, 1996

MEMORANDUM TO: James T. Wiggins, Director
Division of Reactor Safety

FROM: Hubert J. Miller
Regional Administrator
Region 1

SUBJECT: AUGMENTED INSPECTION TEAM CHARTER FOR THE REVIEW OF THE HADDAM NECK NON-CONDENSABLE GASES IN THE VESSEL HEAD AND LOSS OF DECAY HEAT REMOVAL CAPABILITY.

On September 1, 1996, Haddam Neck operators responded to a lowering pressurizer level event with the plant in cold shutdown. Pressurizer level was maintained between 10% and 5% over a four hour period by adding water from the refueling water storage tank (RWST) to the reactor coolant system (RCS). Approximately 5000 gallons of water was added. Operators had been in the process of correcting excessive nitrogen usage to the volume control tank (VCT) and isolated a path to the charging line and into the RCS. The licensee believed that the RCS had a continuous vent established and that the non-condensable gases in the upper head were being vented. An earlier evolution to support RCS vessel head removal, which had lowered RCS level to below vessel head flange, was terminated, and operators had reestablished level at 10% in the pressurizer prior to the start of the event. The licensee believes that the gases introduced while lowering the RCS level were not vented upon reestablishing pressurizer level. Throughout the event adequate core cooling was apparently maintained.

Another problem involving through-wall leakage from the body of the A residual heat removal (RHR) heat exchanger inlet valve had placed the decay heat removal system into a one heat exchanger configuration. The A RHR pump was running with the B RHR pump aligned in standby to that RHR heat exchanger. The actual valve body defect still exists and assessment is being done of this valve to determine if it is considered functional; the licensee may examine the other 3 similar valves. Lastly, in order to align the B train RHR with the B train heat exchanger to support radiography of the A RHR heat exchanger inlet valve, the operators attempted to shift to the B RHR pump and identified indications of pump seizure.

Because the event is considered to be complicated and the probable causes are unknown or difficult to understand, per M.C. 0325, Paragraph 05.02, Item c, I have determined that an Augmented Inspection Team (AIT) should be initiated to review the causes and safety implications.

The Division of Reactor Safety (DRS) is assigned the responsibility for the overall conduct of this augmented inspection. James Trapp is appointed as the AIT leader. Other AIT members are identified in Enclosure 2. The Division of Reactor Projects is assigned the

responsibility for resident and clerical support as necessary; and the coordination with other NRC offices, as appropriate. Further, the Division of Reactor Safety, in coordination with DRP is responsible for the timely issuance of the inspection report, the identification and processing of potentially generic issues, and the identification and completion of any enforcement action warranted as a result of the team's review.

Enclosure 1 represents the charter for the AIT and details the scope of the inspection. The inspection shall be conducted in accordance with NRC Management Directive 8.3, NRC Inspection Manual 0325, Inspection Procedure 93800, Regional Office Instruction 1010.1, and this memorandum.

Enclosures:
1. Augmented Inspection Team Charter
2. Team Composition

ENCLOSURE 1

AUG.'" TED INSPECTION TEAM CHARTER

The objectives of this AIT are tc:

1.) Develop a sequence of events for the introduction and removal of nitrogen gas from the RCS. The sequence of events should also include the component failures and restoration of the decay heat removal system capability. The chronology should start early enough to include the last successful use of the B RHR pump and include any evolutions that may have impacted the pump performance. Also include key findings from Objective 7 below.

2.) Assess the shutdown risk and recovery actions available to the operators given the condition of the decay heat removal system during this event.

3.) Assess the quality of the operator actions, procedures, and training which resulted in the introduction of nitrogen gas to the RCS, as well as the second attempt by operators to start the B RHR pump after the first attempt had failed.

4.) Assess the operator actions taken to identify and respond to the nitrogen bubble in the reactor head.

5.) Assess the quality and timeliness of the response by the operations staff to implement compensatory actions for the decay heat removal system component failures.

6.) Conduct a root cause failure analysis, in parallel with the licensee's effort, to establish the causes for the failure of the RHR pump, reactor head vent and the RHR heat exchanger inlet valve leak. Include reviews of other involved equipment such as the VCT and the nitrogen source.

7.) Assess CY management and technical staff (Engineering, Maintenance, Operations, Health Physics, Security, etc) response to this event. Include an evaluation of the timeliness and extent of integration of the CY organization initial event response and recovery, as well as performance relative to reportability decisions, prompt and final operability reviews and use of the corrective action process.

8.) Review the August 28, 1996 manipulation of the CVCS 355 valve, to determine this event's relationship, if any, to the introduction of nitrogen gas to the RCS. Examine the potential for the nitrogen gas introduction into other portions of the RCS piping and loops.

9.) Review all aspects of this event, including the RCS instrumentation available to the operators for monitoring or assessing the extent of core coverage and reactor vessel level while shutdown, for generic implications, particularly relative to industry operating experience with use of N2 as the motive force for the water movement during shutdown conditions.

Schedule:

The AIT shall be dispatched to Haddam Neck so as to arrive and commence the inspection on September 3, 1996. During the site portion of the inspection resident and clerical support is available. The inspection report is due out 30 days after the formal exit. The team leader will also make recommendations to the DRS Division Director regarding the need for conducting a public exit, the appropriate enforcement action, including draft NOVs and enforcement panel materials, followup needed for any issues left open by the team, and, potentially generic issues. Also, the team leader is expected to schedule a post-AIT lessons-learned meeting between DRS and DRP to examine enforcement opportunities relative to the conduct and administration of the AIT.

ENCLOSURE 2

TEAM COMPOSITION

The assigned team members are as follows:

Team Manager:	James Wiggins, DRS
Onsite Team Leader:	James Trapp, DRS
Onsite Team Members:	Tom Shedlosky, DRP
	Eben Conner, DRP
	Robert Depriest, DRP
	Peter Habighorst, DRP
	John Munro, NRR

Attachment 2

AIT Exit Meeting Slides

HADDAM NECK AUGMENTED INSPECTION TEAM

DECAY HEAT REMOVAL SYSTEM CHALLENGES

NRC INSPECTION 96-80

SEPTEMBER 3-16, 1996

MAJOR EVENTS REVIEWED

1. UNDETECTED ACCUMULATION OF NITROGEN GAS IN THE REACTOR VESSEL HEAD

2. TWO INADVERTENT DIVERSION OF REACTOR COOLANT SYSTEM INVENTORY

3. DECAY HEAT REMOVAL EQUIPMENT FAILURES

EXIT MEETING FORMAT

1. SEQUENCE OF EVENTS
2. SAFETY SIGNIFICANCE
3. CONTRIBUTING CAUSES FOR EVENTS
4. EVENT RESPONSE

SEQUENCE OF EVENTS

UNDETECTED INTRODUCTION OF NITROGEN GAS INTO THE REACTOR VESSEL

- On August 28, 1996, an operator incorrectly opened a valve, which resulted in injecting water and then Nitrogen into the RCS.

- The valve was closed, but did not seat properly. This allowed nitrogen gas to continue to leak into the RCS from the volume control tank.

- Nitrogen gas accumulated in the reactor vessel head. Displaced water from the reactor vessel entered the pressurizer.

- On August 29, 1996, ~5000 gallons of water was drained from the RCS in preparation for refueling activities. Later that day, ~1000 gallons was added to the RCS, when the decision was made to suspend refueling activities.

- August 31, 1996, the nitrogen gas bubble growth reached an equilibrium.

- September 1, 1996, nitrogen gas leakage was stopped by isolating the nitrogen to the VCT. Operators added ~4000 gallons to fill the RCS.

INADVERTENT DIVERSIONS OF REACTOR COOLANT SYSTEM INVENTORY

- On August 22, 1996, operators failed to properly align valves while placing the RHR purification system in service. This failure resulted in inadvertently diverting ~500 gallons of RCS inventory to the refueling water storage tank.

- On September 4, 1996, plant operators inappropriately conducted work activities on the RHR containment spray valves which diverted ~300 gallons of RCS inventory to the containment sump.

DECAY HEAT REMOVAL EQUIPMENT FAILURES

- On August 31, 1996, a plant operator identified a leak in the "A" RHR heat exchanger inlet valve. The valve was closed, removing the heat exchanger from service, to isolate the leak.

- On September 1, 1996, the "B" RHR pump failed to start and was found seized. The pump had previously operated on August 19, 1996.

SAFETY SIGNIFICANCE

THIS WAS A SIGNIFICANT PRECURSOR EVENT

Event Parameters

- Operators were unaware of actual reactor vessel level during this event.

- The time to an RCS temperature of 200 °F was approximately 52 minutes if RHR was lost.

- Reactor vessel level decreased to approximately 2 1/2 feet above the point of RHR pump cavitation.

- If the nitrogen gas bubble had continued to grow, it would have caused cavitation in the operating RHR pump.

Decay Heat Removal Challenges

- The two inadvertent RCS drain downs, had operators not taken prompt actions to terminate the diversion, could have resulted in cavitating the operating RHR pump.

- The required boric acid flow path was compromised by the nitrogen gas in the CVCS.

SAFETY SIGNIFICANCE

(Continued)

Decay Heat Backup Systems

- The "B" RHR pump and "A" RHR heat exchanger were not available for service.

- Venting the "B" RHR pump following maintenance was difficult even with the installation of additional vents.

- The loss of RHR procedure requires the charging pumps be operable to refill the RCS. These pumps were not available during this event.

- If the RHR system was lost, timely restoration of forced circulation using a reactor coolant pump would have been difficult.

- Nitrogen gas could have adversely impacted the ability of the steam generators to remove decay heat by natural circulation.

- The low pressure injection system would have been available to remove decay heat.

CONTRIBUTING CAUSES FOR EVENTS

1. Procedure Quality was Poor

- The use of ACP 1.2-5.3, Evaluation of Activities\Evolutions Not Controlled by Procedure, was not consistent with technical specifications requirements.

- The RCS drain down guidance was inadequate

- The vent header procedure was inaccurate and did not provide adequate detail.

- The RHR purification system procedure lacked key sign-offs.

- The RHR system operating procedure guidance lacked important guidance.

2. Failure to Implement Procedures

- Failure of a non-licensed operator to properly perform the RHR purification restoration procedure resulted in the August 22, 1996, inadvertent drain down of the RCS.

- On August 28, 1996, a non licensed operator failed to align the boric acid flow path valves in accordance with procedure steps.

- Operators failed to properly determine temperature and boron concentration prior to opening loop stop valves.

- Operators isolated nitrogen to VCT without a procedure.

- Operators inappropriately closed the loop stop relief valves without a procedure.

3. Lack of a Questioning Attitude

- The lack of a questioning attitude resulted in the operators failing to adequately evaluate reactor coolant system level anomalies.

- Operations failed to respond in a timely manner to the excessive use of nitrogen gas between August 29 - September 1, 1996.

4. Inappropriate Decision Making

- Control room operators failed to properly control plant work activities which contributed to the September 4, 1995, RCS drain down event.

- Operators isolated the loop stop pressure relief valves without properly assessing the technical implications.

5. Pre-Job Briefings were Inadequate

- No pre job briefing before lineup of RHR purification pump on August 22, 1996.

- No pre job briefing before boric acid flow path alignment on August 28, 1996.

6. Lack of Instrumentation

- The RVLIS and CET had been disconnected and were not available.

- The cavity level system did not provide reliable or adequate reactor vessel level indication.

7. Training Not Adequate

- Failed to conduct scheduled re-qualification training on outage and refueling operations.

- Training conducted on RCS level indication and vent header operation was weak.

8. Poor Equipment Condition

- Several isolation valves in the CVCS system leaked by causing a leak path for nitrogen.

- A leaking manual RHR containment spray isolation valve allowed RCS to be diverted the sump.

- Poor design control and material condition of the temporary reactor head vent system.

9. Poor Implementation of Generic Information

- In 1994 CY staff failed to implement several recommendations made by technical support in response to NRC Information Notice 94-36.

10. Weak Use of Technical Support

- Operators failed to solicit technical support for identifying the source of nitrogen gas usage.
- Operators did not solicit technical support to evaluate perceived loop stop valve leakage or to develop corrective action plans.
- Operators did not solicit technical support in developing a more detailed drain down procedures.
- Technical Support did not provide operators with local RVLIS or CET readings.
- Work occurred on RHR containment spray valves without System Engineers knowledge.

11. Inappropriate Planning and Scheduling

- The schedule change to stop refueling activities over the weekend was not thoroughly reviewed for safety.

- Implementation of the September 4, 1996 work activities that resulted in RCS inventory diversions was not consistent with the work control procedure to minimize shutdown risk.

EVENT RESPONSE

1. Slow Initiation of Event Review Team

- The incident response team was not in place until 4 days following this event.

2. Untimely Technical Response

- Local RVLIS and CET readings were not taken for 2 days.
- Additional surveillance of the operating RHR pump were not implemented for 5 days.
- The RCP and seal injection were not aligned for service for several days.
- Special tests to establish vessel level and vent header operation were not performed for 4 days.

3. Avoidable Delays in RHR Pump Repair

- Several avoidable delays were encountered during the replacement of the "B" RHR pump.
- Time to restore "B" RHR pump to operable status was 25 days.

4. Failure to Report Event

- The required 4-hour 50.72 event report was not made for 10 days.

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title:	CONNECTICUT PUBLIC TELEVISION BROADCAST RE NUCLEAR SAFETY ISSUES
Docket Number:	(not applicable)
Location:	TELEVISION BROADCAST
Date:	AUGUST 29, 1996
Work Order No.:	NRC-951

Pages 1-59

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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SAFETY ISSUES

+ + + + +

CONNECTICUT PUBLIC TELEVISION BROADCAST

+ + + + +

AIR DATE: AUGUST 29, 1996

+ + + + +

IN THE MATTER OF

EXHIBIT A TO 10 CFR 2.206

PETITION DATED 11/25/96 ON BEHALF OF

CITIZENS AWARENESS NETWORK (CAN)

AND

NUCLEAR INFORMATION AND RESOURCE SERVICE (NIRS)

The interview was held at Connecticut Public Television, Susan Perry Luxton, moderator, and Gary Verdun, guest speaker.

P-R-O-C-E-E-D-I-N-G-S

(Introductory music.)

MS. LUXTON: Hi, I'm Susan Perry Luxton, and welcome to Nuclear Safety Issues brought to you by the Citizen's Regulatory Commission. This evening I have with me a guest who was a former employee of Millstone, Gary Verdun. Gary, glad to have you here.

MR. VERDUN: Pleased to be here, Susan.

MS. LUXTON: Gary is a very powerful speaker who we started to hear at the last few meetings, and we have never heard before that. And so, he has quite a story to tell relating to his experience working at Millstone, and also the termination of January 11, 1996.

And so I thought it was something that you should all hear because I was duly impressed by -- not impressed, upset's the word more, I think, by -- by what I heard from Gary. So Gary, let's talk a little bit about your background first.

How long have you been at Millstone or were you at Millstone before you were terminated?

MR. VERDUN: Well, I started at Millstone in 1980, and I worked there for 12 years as a Senior Engineering Tech in a group called the Liability Engineering. And after 12 -- 8 years -- 12 years with the company, I should say, I was promoted to Site Maintenance

Supervisor.

And at the point in time, I took on a major responsibility of assuring that the site was in good condition with respect to material condition of the site, the cleanliness of the site, the --

MS. LUXTON: The "site," you mean all three reactors?

MR. VERDUN: All of the support buildings, grounds, the maintenance of all support buildings on the units and some support for the units themselves.

MS. LUXTON: "Material condition," you mean hardware and housekeeping?

MR. VERDUN: All -- all the housekeeping on the site and all the maintenance of the support buildings --

MS. LUXTON: Yes.

MR. VERDUN: -- HVAC work, repair of all the doors on the site, which there's a couple of thousand doors, and all of the janitorial services --

MS. LUXTON: Yes.

MR. VERDUN: -- for the site.

MS. LUXTON: Yes.

MR. VERDUN: So, the job was a pretty big job.

MS. LUXTON: It sounds like a big job.

MR. VERDUN: And it -- it was different from

the previous job because the previous job was all technically oriented, and it involved a lot of work on solving rotor dynamics problems --

MS. LUXTON: Yes.

MR. VERDUN: -- problems with rotating equipment, vibration problems on -- on large rotating equipment. So --

MS. LUXTON: In nuclear -- in the nuclear field?

MR. VERDUN: All in -- well, we did work on the nuclear plants as well as fossils and hvdro plants.

MS. LUXTON: And this was when you were with Combustion Engineering --

MR. VERDUN: No, this was --

MS. LUXTON: -- or when you went --

MR. VERDUN: -- this was with North -- Northeast Utilities --

MS. LUXTON: All right.

MR. VERDUN: -- from 1980 until about 1992, I did that kind of work. And then from '92 until 1996, I worked at the site as Site Maintenance Supervisor.

MS. LUXTON: Okay, so that's 19 -- so, 19 -- is that 16 years?

MR. VERDUN: Sixteen years, yes.

MS. LUXTON: (Laughing).

MR. VERDUN: A lot of the years at Northeast Utilities were wonderful years. If I was really -- since 1987, when the plants really began to have problems and we saw -- began to see a degradation at the plant in terms of the condition of the plant, in terms of procedural violations, in terms of, you know, morale problems beginning to surface at the plants, and this all kind of coincided with cut-backs that were imposed on the staff as a result of the company trying to position themselves in a competitive situation --

MS. LUXTON: Yes, yes.

MR. VERDUN: -- for things that were coming down the pike with retail wheeling --

MS. LUXTON: Deregulation?

MR. VERDUN: -- and deregulation and -- and that kind of thing.

MS. LUXTON: Yes.

MR. VERDUN: So, a lot of problems began to emerge in 1987 as a result of cut-backs at the site: money cut-backs, manpower cut-backs, and that sort of thing. And by the time I became a supervisor in 1992, the cut-backs were really becoming very severe.

And -- and then they were beginning to talk about staff reduct... s to the Northeast Utilities' staff. And of course, that -- that heightened and increased the

concern of the employees for their jobs and it had a detrimental effect on morale --

MS. LUXTON: Yes.

MR. VERDUN: -- along with severe budget cuts from 1992 until 1996. That bunch of cuts were so severe that the degradation at the plant began to increase at a faster rate.

MS. LUXTON: And you were involved with -- talking about degradation of the plant -- of identifying those kinds of problems --

MR. VERDUN: Yes.

MS. LUXTON: -- by -- by your MCP --

MR. VERDUN: Material Conditions Program.

MS. LUXTON: -- program? Right. That was -- so, let's talk a little bit -- but first, I think, talk about the Material Condition Program, because that was a big part of what -- what you -- you did at Millstone in those last final years.

MR. VERDUN: Yes, it was.

MS. LUXTON: But was -- that had to do with the housekeeping, right? And -- and when you talk about "housekeeping," we were talking about that earlier today, and that was an interesting thing to learn: how important that is in a nuclear power plant.

MR. VERDUN: Housekeeping --

MS. LUXTON: I mean, it's not just like sweeping the floor.

MR. VERDUN: No, there's a lot more to it than that. Housekeeping is a very important issue --

MS. LUXTON: Why?

MR. VERDUN: -- at nuclear power plants because it involves aspects of fire safety. And fire safety at nuclear power plants is a very important issue. So, it's very important to keep the plants very clean and in a condition that looks good to everybody, and not only looks good, but is safe from the standpoint of combustionable materials and --

MS. LUXTON: Right.

MR. VERDUN: -- and that sort of thing.

MS. LUXTON: They're not tripping over things. There's not rags --

MR. VERDUN: Right.

MS. LUXTON: -- and whatever --

MR. VERDUN: Right.

MS. LUXTON: -- hanging out.

MR. VERDUN: Right. Part of it is keeping things tied down, keeping everything in order, and everything has a place and everything should be in its place.

MS. LUXTON: And that's the fire safety part,

but there's also the radiation part --

MR. VERDUN: Yes, that --

MS. LUXTON: -- for instance, in rad waste.

MR. VERDUN: Yes, that -- that -- those kinds of issues are normally taken care of by a whole crew of people that are assigned to rad waste.

MS. LUXTON: Yes.

MR. VERDUN: But the -- one of the jobs that I got --

MS. LUXTON: Then what were the people doing if -- if they weren't -- if they had a whole crew of people in charge of rad waste, Gary, what were they doing all these years that they let rad waste go like that?

MR. VERDUN: You're talking about Unit I rad waste?

MS. LUXTON: Right, Unit I rad waste, when they --

MR. VERDUN: Basically, I think they became complacent with a very bad situation, an antiquated facility --

MS. LUXTON: Yes.

MR. VERDUN: -- that certain piping systems that process radioactive waste were antiquated. They'd been cut out of the piping loop. Some pumps had been shut down, were no longer used.

A lot of the systems in there were still radioactive pipes. They hadn't disposed of those pipes or cut them out of the system because it was going to be just too expensive, the Utility thought, to dispose of those systems at that time --

MS. LUXTON: Right.

MR. VERDUN: -- because of the radiation aspects of it.

MS. LUXTON: So, they allowed it to just kind of deteriorate and deteriorate and they didn't get the money --

MR. VERDUN: So --

MS. LUXTON: -- the funding --

MR. VERDUN: Yes.

MS. LUXTON: -- the department people didn't get the funding to clean it up, so they just kind of lived with it?

MR. VERDUN: The -- the technicians and the people that had to work in those areas lived with that situation. They kind of became used to it. And it really wasn't until I was assigned a major project by Don Miller about a year and a half ago.

It was near Thanksgiving in 1994, that I -- I was asked to do a special assignment where I reported directly to him and -- and created a program called the

Material Condition Program for the site, which was basically a comprehensive inspection program, a visual inspection program, of the site to identify any kinds of deficiencies that we could see, hear or sense by sensory perception. And at that time,

MS. LUXTON: What do you mean by "sensory perception?"

MR. VERDUN: Well --

MS. LUXTON: I know there's something wrong --

MR. VERDUN: (Laughing).

MS. LUXTON: -- (Laughing).

MR. VERDUN: No, no. We -- we didn't have any --

MS. LUXTON: No fortune tellers there, right?

MR. VERDUN: -- ESP kind of stuff going on there, or at least I don't think we did. (Laughing).

MS. LUXTON: So, who was in charge, you?

MR. VERDUN: I was in charge of the program, and the program basically -- I was -- I was told what the company wanted for a program and some of the fundamental aspects of the program. And then I was turned loose to design the program and come up with something that would work for the site for a comprehensive inspection program.

So, what I came up with after a fashion was -- and -- and working with Don Miller on this also was we

would have 28 managers from the site, the Millstone site, perform inspections once a month.

It would take about four to six hours of their time per month. Each of the managers would be assigned a zone to inspect, which was a -- like a small geographical area of the site.

MS. LUXTON: Yes.

MR. VERDUN: Their job would be to go into that area, or those areas, that they were assigned to, and they would look for deficiencies --

MS. LUXTON: Yes.

MR. VERDUN: -- any kind of deficiencies: housekeeping deficiencies, leaks in pipes, noisy machinery, machinery that was vibrating excessively that might be developing a problem.

MS. LUXTON: Okay, why?

MR. VERDUN: To -- to basically put the plant in a better material condition. We were trying to identify problems that we could later, you know, get them identified in a database, and then organize an effort to get these things repaired.

MS. LUXTON: So you could become an exemplary nuclear power plant?

MR. VERDUN: That's right, because the condition of the site was beginning to look very haggard.

MS. LUXTON: Yes.

MR. VERDUN: And Don was, and many other people were, very concerned about that.

MS. LUXTON: Yes.

MR. VERDUN: And it slipped, like I said, since 1987. So, this assignment came along in November of 1994. It had slipped into a pretty seriously -- a pretty bad state of affairs --

MS. LUXTON: Yes.

MR. VERDUN: -- from appearance and also from the condition of the machinery and the performance of the machinery. So --

MS. LUXTON: So, this was a good thing?

MR. VERDUN: Oh, it was an excellent program.

MS. LUXTON: Yes.

MR. VERDUN: I spent a lot of time designing the program, setting up tracking systems for the program.

MS. LUXTON: Did --

MR. VERDUN: Eventually, we created a huge database.

MS. LUXTON: Yes. How many -- how many things did you find wrong that needed to be fixed?

MR. VERDUN: In a year and a half, we identified 2,613 items that were entered into the database that needed to be addressed. Like I said before, a lot of

them were minor things: housekeeping issues, appearance things.

MS. LUXTON: Yes.

MR. VERDUN: But there were some things in the database that had far-reaching implications in terms of effort, money, engineering, time, and, you know, really seriously impacted the --

MS. LUXTON: Performance of the plant?

MR. VERDUN: Yeah, and not only that, but the -- you know, the radiation exposure of personnel and the safety of people working around that kind of material.

MS. LUXTON: Yes, okay. So, what happened?

MR. VERDUN: Well, probably the best example really was the, like you mentioned earlier, the Unit I rad waste facility. When I went into that facility for the first time in my life, I was -- I was approached by people that were working in those areas.

And basically, they were concerned about conditions that they were asked to work under --

MS. LUXTON: Yes.

MR. VERDUN: -- because the area was so -- it was strewn with temporary pipes, temporary hoses, temporary processing equipment. There were lots of pipes in there that were still radioactive pipes that were not being used to process fluid, but hadn't been removed that,

you know, people had to work around these things and walk by them all the time.

So, the people felt that, you know, they were getting exposure, that -- radiation exposure that they didn't have the --

MS. LUXTON: That was not necessary.

MR. VERDUN: -- necessary, and there was a lot of contamination, of course, in that area because of the fact that they're processing these fluids.

What was particularly bad about it is that all of these hoses and tubes running all over the floors and everything were not plumbed into the system as hard piping systems in a permanent manner.

Everything was kind of temporarily set up. You know, it looked to me like it --

MS. LUXTON: And it had been temporarily set up for years you mean?

MR. VERDUN: For years and years. And -- and -- and everything -- every time they did something down there, it was always done temporary, you know, temporary. So, they'd take out one temporary thing, and put in another temporary thing. As technology changed and better things came along, they'd take out one temporary thing and put in another, I guess.

So, but they never got to a point where they

ever plumbed anything back in hard, you know --

MS. LUXTON: Oh, I see.

MR. VERDUN: -- with piping systems. So, it was a mess.

MS. LUXTON: So, what finally happened, Gary? Did they fix it? I mean --

MR. VERDUN: Well, they didn't --

MS. LUXTON: -- they didn't fix it then.

MR. VERDUN: After -- after a lot of discussion about it and after working with one of the managers that was responsible for inspections in that area, we got an engineering effort mounted to correct those problems.

One of the major things though that -- two things -- two major things in that area that concerned me a great deal: one of them was a tank that had a -- that had rotted out. And apparently, there was radioactive sludge that was leaking out of the base of the tank.

The technicians in that area referred to this -- this condition that had developed there as the ant hill. So, the sludge would leak out slowly and a mound of radioactive sludge had built up underneath the tank that was extremely hot stuff.

So, somebody somewheres along the line decided that it was going to be too expensive to repair this tank,

take it out or put a new tank in because of the high radioactive levels. So, they essentially put up a concrete wall around the whole thing and kind of roped it off and, you know, put a lead shield in and stuff like that, and left it there.

So that, I thought, was, you know, an extreme situation that absolutely should have been corrected. It shouldn't have been a question of economics. It just should have been fixed.

MS. LUXTON: Yes, yes.

MR. VERDUN: So, I made an issue out of that. And I tried to get the films that people had taken on an inspection a year or two before. I never could get the films. I kind of was jerked around, so I never saw the actual films.

I understand that they were taken during an NRC inspection -- inspection. So, NRC people --

MS. LUXTON: Was aware of it?

MR. VERDUN: -- knew about it. They had seen it, and they had not --

MS. LUXTON: Years before?

MR. VERDUN: Years before, and they had not imposed a situation on those plants -- on that -- on the plant to correct that situation.

There's a pipe chase down there also that I

understand is an extremely bad situation that is corroded out, a rotted out system, that's an extremely hot area that people have been into, and is another area that technicians are very, very concerned about down there.

And I began to raise, you know, issues about getting that area corrected also.

MS. LUXTON: Okay.

MR. VERDUN: So, there were -- there were big things that came out of this program. It was not all just, you know, painting --

MS. LUXTON: Right, right.

MR. VERDUN: -- floors and machinery and --

MS. LUXTON: And fixing valves and whatever?

MR. VERDUN: -- and fixing the valves. There were other things that were involved that were big, big items.

MS. LUXTON: Yes, like how about the thing with the chips, the paint chips in Reactor Building II?

MR. VERDUN: Oh, where the containment --

MS. LUXTON: I love that story, in the containment.

MR. VERDUN: Well --

MS. LUXTON: Was that part of your deficiency?

MR. VERDUN: Well, there -- there was a condition in contain -- that you're talking about --

MS. LUXTON: Yes.

MR. VERDUN: -- that's in Unit II --

MS. LUXTON: Yes.

MR. VERDUN: -- containment where the -- there's a steel liner that circles containment --

MS. LUXTON: Yes.

MR. VERDUN: -- that is basically bolted to the --

MS. LUXTON: Cement?

MR. VERDUN: -- the concrete --

MS. LUXTON: Yes.

MR. VERDUN: -- the cement --

MS. LUXTON: Yes.

MR. VERDUN: -- which is eight or ten feet thick.

MS. LUXTON: Yes.

MR. VERDUN: This liner is a quarter of an inch or a half an inch thick, something like that. And it -- it's a painted -- the liner is painted.

MS. LUXTON: Yes.

MR. VERDUN: And my understanding of what occurs in that area is that during thermal temperature change that's inside a container, that the -- this shell grows faster than the concrete does because it heats up at a quicker rate from the changes in the air temperature and

the ambient temperature inside the containment.

So that what's created there is a differential thermal expansion --

MS. LUXTON: Yes.

MR. VERDUN: -- between the liner and the concrete. And as that -- as that liner tries to grow -- tried to grow out against the concrete, which is not growing at the same rate, so it -- since it tries to grow out, it can't go anywhere outwardly. So, it ends up buckling.

So, that liner is buckled in several areas inside containment because of the differential thermal expansion problem. But what comes into play here is that it put such tremendous stresses on the liner, that the paint that's applied to the liner peels off. And it peels off in chunks that are about the size of giant potato chips, probably so big. They just curl right off the liner.

The -- the problem with the situation there is that there are so many of these paint chips that have peeled off the liner that when -- and this occurs on -- usually on start up --

MS. LUXTON: Yes.

MR. VERDUN: -- or during the process of running -- you know, while they're running the reactors,

that a lot of these paint chips begin to appear. And what has concerned the plant, and they've known about this for years, is that if there's ever an accident inside of Unit II and they have to spray down inside the containment, there's a good possibility that all that water rushing out of the sparges and all the piping systems that are used to quench the steam inside the containment, all that water hitting those potato chips, or paint chips, could bust the paint chips off, break them free.

They would fall to the floor --

MS. LUXTON: And clog up the drain.

MR. VERDUN: -- where there would be a torrent of water running across the floors. They would go into the drain, clog the drains. And in those sumps where the drains are, those -- that's the suction for the pumps that then recirculate the water, bring it back up to the spraying headers and then re-spray it to continue quenching steam and keeping, you know, whatever situation has developed under control.

MS. LUXTON: Right. So, if it was -- so technically then, theoretically, if that was clogged, then they wouldn't be able to quench the steam.

MR. VERDUN: Right.

MS. LUXTON: And the steam would build up and that would be a pressure --

MR. VERDUN: That would create --
MS. LUXTON: -- problem.
MR. VERDUN: -- some major problems --
MS. LUXTON: Right.
MR. VERDUN: -- inside there because they would not -- no longer have a source -- well, it would eliminate one major source of water that they would need to control a situation inside containment.
MS. LUXTON: Okay, now --
MR. VERDUN: So, that's a scary situation.
MS. LUXTON. It's a scary situation.
MR. VERDUN: And it's something that --
MS. LUXTON: And you identified several --
MR. VERDUN: -- needs to be addressed.
MS. LUXTON: -- of these.
MR. VERDUN: So, that --
MS. LUXTON: Similar.
MR. VERDUN: -- the painting problems inside the containment were identified by --
MS. LUXTON: By this program?
MR. VERDUN: -- this program, yes.
MS. LUXTON: Right. Okay now, the bottom line is what happened to the program? Did they do the inspections month -- every three months? And did -- did -- and -- and so where's the program now?

You are no longer there. Where's the program? That's the question?

MR. VERDUN: Well to my knowledge, when -- when I was terminated or laid-off, whatever you'd like to call it, they -- they use the euphanism, you know, "laid-off." But really, essentially what it was was an illegal termination.

MS. LUXTON: Yes.

MR. VERDUN: Nobody wanted to go and it was not necessary for anybody to leave. At that point in time, this Material Condition Program essentially was abandoned to the best of my knowledge.

I know of nobody that picked up on the program to administer the program, to --

MS. LUXTON: What about Mr. Miller? It was his program.

MR. VERDUN: I don't know. Basically, I tried to contact Mr. Miller after the termination to see if they would want to bring me back in through some, you know, job shop --

MS. LUXTON: Contract, oh, yes.

MR. VERDUN: -- to work for Millstone to continue to administer the program. But, I was referred to -- to the new senior person on the site, and basically didn't get a call back from him. Later called again to

another vice president who had been involved in this, and -- and he referred it to a director, who was the director I worked for prior to being terminated.

He did call and he told me in a phone conversation that they -- they would decline the offer at that time. They weren't interested in identifying any new problems at the site. They were focusing all their attention on problems that they already knew about, which --

MS. LUXTON: Well, these aren't new problems --

MR. VERDUN: -- pretty much astounded me because, you know, they should continue to look for problems all the time at those sites. It's an ongoing, living process.

MS. LUXTON: Right, right.

MR. VERDUN: It's not something that you just, you know, abandon at some point in time. But the bad part --

MS. LUXTON: Well, but --

MR. VERDUN: -- about it --

MS. LUXTON: -- they don't really want to know though, Gary, I don't think.

MR. VERDUN: I doubt it because --

MS. LUXTON: Because --

MR. VERDUN: -- this program was essentially abandoned as far as I can see, and the database has not changed from the time that I, you know -- I was -- I was terminated at the site.

MS. LUXTON: Seven months ago or whatever. Now, do you think that this program that you did was just getting a little bit too close for comfort for them, and that's part of the reason why you got terminated?

MR. VERDUN: Well after a lot of thought on the issue, you know, I could think of no sensible reason why I was terminated. Essentially, I was doing two jobs for the company. I was performing the duties of a Site Maintenance Supervisor. I was doing everything I could to do as much as possible in that area.

And I was performing the duties of this Material Condition Program. It's a very large job. It involved a lot of effort to maintain the databases and organize the --

MS. LUXTON: Yes.

MR. VERDUN: -- the effort.

MS. LUXTON: And to take it home work, you did at home.

MR. VERDUN: Oh yes, a lot of -- a lot of times I took stuff home, and then get reports out to all the senior level management. You know, reports went out

to about 50 people that were tailored to their level --

MS. LUXTON: Level.

MR. VERDUN: -- in the company, so that everybody knew exactly what all the problems were at the site, so that the appropriate people could put pressure on the right people to get all these deficiencies cleaned up.

MS. LUXTON: But see, this is what I see, Gary. This is exactly what they were talking about at the NU meetings with the NRC. They had all these studies. They put all this money into this enormous program to get the place in better shape, and then they just let it go.

MR. VERDUN: And then they abandoned it, right.

MS. LUXTON: And they abandoned it. And even before they terminated you and it was abandoned, people weren't even doing it.

MR. VERDUN: Well, we had problems -- Miller had problems right along with getting some of the managers to do their inspections. And he was frustrated with that.

MS. LUXTON: Yes.

MR. VERDUN: And he tried 00 a number of times I was at meetings where he actually raised some hell about it with the managers. But, it didn't seem to make any difference.

At first, it seemed to be a very effective

program and the managers were -- managers were participating. But as time went by, the effort tapered off until we got down to, you know, I think it was around 50 or 60 percent participation --

MS. LUXTON: Yes.

MR. VERDUN: -- per month by manager. And you know, by then, you know, things were beginning to fall off rapidly. It felt that upper level management was not supporting this program.

MS. LUXTON: Yes.

MR. VERDUN: And I was beginning to get some negative reactions from my director and my supervisor. Some things happened in the office area that could certainly be considered harassment by both my supervisor and my director.

MS. LUXTON: Towards you?

MR. VERDUN: Towards me.

MS. LUXTON: Yes.

MR. VERDUN: And I began to feel that this Material Condition Program was getting too hot for the company to handle.

MS. LUXTON: Yes, yes.

MR. VERDUN: So, I went to Nuclear Safety Concerns, who was supposed to be a safe island for people to go to --

MS. LUXTON: Right, right.

MR. VERDUN: -- when they think they're having problems that involve nuclear safety concerns issues.

MS. LUXTON: Yes.

MR. VERDUN: I talked to them about it, and basically I was told that, you know, they would discuss the situation with my supervision: my director and my immediate supervisor and with Don Miller and, you know, they would try to resolve the problem.

So after several weeks or so, there were -- there were meetings about it. And we -- I thought that we pretty much had resolved the issues, and that, you know, this harassment would stop and --

MS. LUXTON: Yes.

MR. VERDUN: -- and that things would work out --

MS. LUXTON: And what happened?

MR. VERDUN: -- okay. And about two weeks, two or three weeks after the meeting, I was told that I was terminated. So, you know, I basically -- I went -- I followed the company procedures. I worked within the guidelines and framework of the company.

I believed in what they told me about working within the system --

MS. LUXTON: Yes.

MR. VERDUN: -- that the company set up --

MS. LUXTON: Yes.

MR. VERDUN: -- for a nuclear safety concerns issue. I gave them due respect to work within that system.

MS. LUXTON: Yes.

MR. VERDUN: And it -- they did not protect me. They -- they -- they betrayed my trust, and basically I was set up for the situation that --

MS. LUXTON: That you're in now?

MR. VERDUN: -- finally transpired.

MS. LUXTON: I'm sorry, Gary. I hate to say it, but you're one in a long list, an ever-growing list. And hopefully, it won't be growing any longer now.

I mean, they keep saying that -- that they've changed and that they're so much better, the Nuclear Concerns Program, but I don't believe it. Let's talk about this matrix business, about the -- about the termination.

MR. VERDUN: This is going to be the joke of all jokes.

MS. LUXTON: We've heard this before from --

MR. VERDUN: Yes.

MS. LUXTON: -- Jim Plum, from Harry Scully. I mean, this is the joke of all jokes.

MR. VERDUN: Yes.

MS. LUXTON: How many years did you have experience, 16 years experience? Guess what? In the rating folks, the rating -- they had -- they were rated in different weights. In experience, the weight of experience was two.

MR. VERDUN: Yes.

MS. LUXTON: I can't believe that experience is only rated two.

MR. VERDUN: Well --

MS. LUXTON: Education was rated the next lowest, five.

MR. VERDUN: There -- there's nothing sensible about this process at all. I mean, it's -- it's a very subjective process.

MS. LUXTON: One man did this?

MR. VERDUN: One man basically did this to me, that's right. One man, who took probably ten minutes to fill this matrix out, changed the course of my life forever.

And nothing that was on this matrix was based on past performance review; nothing was based on the effort that I put forth for the company; nothing was based on, you know, the fact that essentially I was working two jobs for the company.

MS. LUXTON: Yes, yes.

MR. VERDUN: It wasn't involved with -- it didn't have any bearing on -- with me or with anybody else, by the way, that was involved with this matrix --

MS. LUXTON: So, you feel that --

MR. VERDUN: -- nobody was treated fairly.

MS. LUXTON: Right. So, you feel you were wrongly terminated.

MR. VERDUN: Oh, absolutely.

MS. LUXTON: So, what -- so, this is a part of the show that we want to talk about too. I would like, if there's anyone watching who also was on that January termination and would like to -- to call in and maybe share what happened with them and how they felt about their termination -- maybe you felt it was fine.

And I don't know if anybody feels that their termination is fine. But you're actually saying you think it was illegal.

MR. VERDUN: Well, I think it was illegal because what -- what first alerted me to the fact that this might be illegal is I went to an NRC meeting --

MS. LUXTON: Yes.

MR. VERDUN: -- in a simulator building at -- at Millstone.

MS. LUXTON: Yes.

MR. VERDUN: And I think it was two or three weeks ago. And during that meeting, I was surprised to find out that the NRC made a statement that -- when they were asked about these terminations and whether -- how the investigation was going --

MS. LUXTON: Yes.

MR. VERDUN: -- from the standpoint of the NRC looking into this stuff, that basically the investigation of the firing of 104 people had not been completed, that it had kind of been bounced around within NRC structure, Office of Investigation, that they had pretty much come to the conclusion that they might refer the whole matter to the Justice Department.

MS. LUXTON: Yes.

MR. VERDUN: And if it went to the Justice Department, that there could be criminal prosecution --

MS. LUXTON: Yes, yes.

MR. VERDUN: -- as a result of the whole affair. Because a lot of these people that were terminated by use of this crazy thing that Northeast Utilities developed to target people that they wanted to -- to terminate, for whatever paranoid reasons that were going through their mind, they -- a lot of them were involved in nuclear safety issues.

MS. LUXTON: Yes, yes.

MR. VERDUN: So if that can be linked to -- you know, these terminations can be linked to illegal --

MS. LUXTON: Then criminal prosecution can be --

MR. VERDUN: Yes.

MS. LUXTON: -- can be on the horizon. Now listen --

MR. VERDUN: That's right.

MS. LUXTON: -- the key word here is "criminal prosecution."

MR. VERDUN: That's right.

MS. LUXTON: Now, we were going to show the folks at home the Code of Federal Regulations, remember?

MR. VERDUN: That's true, yes.

MS. LUXTON: Now, Gary brought in the C.F.R, the Code of Federal Regulations. Now, you've heard many times on our show, and also in the newspaper -- I mean, you can't have followed this issue without seeing these letters, "C.F.R. 20.20" or "C.F.R. 50.54."

So, this is what C.F.R. is, the Code of Federal Regulations. These are the laws that guide the nuclear power plant in its operations, right?

MR. VERDUN: That's right.

MS. LUXTON: Okay. So in this C.F.R. 50 -- 50 section, we looked up the employee protections part of it,

C.F.R. 50.7. And here it says, "Discrimination by a licensed -- commissioned licensee against an employee for engaging in certain protected activities is prohibited. Discrimination includes discharge and other actions that relate to compensation, terms, conditions or privileges of employment."

And then it goes on. And then it says, "Any employee who believes that he or she has been discharged or otherwise discriminated against by any person for engaging in protected activities specified in Paragraph (a) -- (a)(1) of this section, may seek a remedy for the discharge or discrimination through an administrative proceeding in the Department of Labor," which you've done.

Okay, and then it says, "Violation of Paragraphs (a), (e) or (f) of this section by a commissioned licensee," that would be like NU, "an applicant for a commissioned licensee, or a contractor or a subcontractor of a commissioned licensee or applicant may be grounds for (1) denial, revocation, or suspension of a license; (2) imposition of civil penalty on the license or applicant; and (3) other enforcement action."

Now, this is a big point because "harassment and intimidation of employee," not -- whether you're wrongfully terminated or not. Whether you were wrongfully terminated or not is one issue.

But the harassment and intimidation, we know that has gone on more than once, right?

MR. VERDUN: Absolutely.

MS. LUXTON: More than twice. I mean --

MR. VERDUN: Absolutely.

MS. LUXTON: -- the people we've had on this show: Blanche, Delcort --

MR. VERDUN: Plum.

MS. LUXTON: -- Plum, Tim O'Sullivan, Gladys, and Benttencourt, all those people, you -- I mean, we're talking up to six, seven, eight, nine -- and Pete Reynolds. I mean, if this -- with the (a) violation, we've got five or six. Why isn't the NRC --

MR. VERDUN: Wait, we have nine.

MS. LUXTON: What -- nine.

MR. VERDUN: Nine up to this point. Now --

MS. LUXTON: That's with the --

MR. VERDUN: I believe that, you know, that I -- that I am the tenth person who's come forward to say that they think that they were treated wrongfully by they company with respect to the protected activities.

MS. LUXTON: Okay, so it says right there --

MR. VERDUN: So I mean, this -- this is a repeating occurrence at this utility. It's something that needs to be corrected.

MS. LUXTON: By the NRC.

MR. VERDUN: And the NRC needs to take some real tough action, and they need to take action against the people that are doing this things, not against the corporation.

There are people involved in this stuff that need to be -- need civil penalties --

MS. LUXTON: Right, so -- so the civil --

MR. VERDUN: -- because they're violating federal rules when they do these things.

MS. LUXTON: Right, or "the denial or revocation or suspension of a license or other enforcement action." Well what they've been doing is the "other enforcement action."

MR. VERDUN: Right, but they have never -- they have never taken --

MS. LUXTON: Complied.

MR. VERDUN: -- their licenses away from them. They've never revoked their license. They've never really played hard-ball with this utility. They give them a $100,000 fine or something. A $100,000 fine to this utility is a joke.

MS. LUXTON: Right.

MR. VERDUN: I mean, they laugh about it. It's like you and I going out and getting a speeding

ticket --

MS. LUXTON: Yes.

MR. VERDUN: -- and then they got -- the officer writes it out and says that this is a four cent fine.

MS. LUXTON: (Laughing).

MR. VERDUN: You know?

MS. LUXTON: That's a real deterrent, right?

MR. VERDUN: Yes, so, you know, it's that kind of thing.

MS. LUXTON: Well, we've got a call.

MR. VERDUN: The penalties are not severe enough.

MS. LUXTON: Let's see who it is. Hi, you're on Nuclear Safety Issues.

MALE PHONE CALLER: Yes, hi, Susan. How are you?

MS. LUXTON: Good.

MALE PHONE CALLER: Great. And your guest, good to see him, but not in these conditions that, you know --

MS. LUXTON: Yes.

MALE PHONE CALLER: -- that are prevailing. But you know, he was talking, and you also were talking of rad waste, et cetera. And at one time, I did work for rad

waste.

MS. LUXTON: Oh, did you?

MALE PHONE CALLER: Yes. And I'm going to tell you what -- just exactly what transpires out there, and it's one of these things to hell with it -- to hell with it. That's the big word, and the gentleman is agreeing with me, shaking his head yes.

MS. LUXTON: What do you mean --

MALE PHONE CALLER: But it --

MS. LUXTON: -- "to hell with it?"

MALE PHONE CALLER: I'll tell you exactly what's happened. We've had episodes out there where I have actually been in Unit II. I've done work in there: piping, et cetera. I've seen puddles on the floor.

And I've been told, "Clean that up." I've said, "Let's get PHP in here and let's get a test going on it," --

MS. LUXTON: Yes.

MALE PHONE CALLER: -- and so on. "Just wipe it up and then we'll -- we'll check the rags up after you wipe it up," blah, blah, blah. "We have messoline rags," et cetera.

Then you say, "No, I -- you know, get somebody down here first." Well, they would raise cain with you. And then the next thing would be, "To hell with it. Just

leave it. Go over and do that over there."

Now, many a time I have seen puddles that have been -- been, excuse me, been tested, and the counters would just go so erratic, it would -- it would make your head spin.

MS. LUXTON: The radiation counters?

MALE PHONE CALLER: Certainly, quite certainly. You know, you had leaks here, there and everywhere.

MS. LUXTON: So --

MALE PHONE CALLER: And every time you reported a leak, you were a pain in the neck, you know? "What were you doing over there? What were you doing over here?" I, one time, worked out there for one solid week in one particular area, and I don't know how many reports I made for one valve dripping, one valve.

I kept reporting that valve and reporting that valve. I was finally told, "Why don't you mind your business?"

MS. LUXTON: Really?

MALE PHONE CALLER: That's right.

MS. LUXTON: I mean, I -- why do I say "Really?"

MALE PHONE CALLER: That's right. Well, three weeks later I finally went back in that area, three weeks

later, and that valve was still dripping.

MS. LUXTON: Oh.

MALE PHONE CALLER: Okay? Now, I went back to my boss and told my boss. I said, "What in the hell is going on around here?" He said, "Don't get involved in junk like that." Can you imagine?

Well needless to say, I don't work for Millstone. I got the hell out of there --

MS. LUXTON: I'll tell --

MALE PHONE CALLER: -- because I -- I just couldn't take it anymore up there, you know?

MS. LUXTON: Well, you know, I think you probably did a good thing for your health-wise too, because those are not the kind of conditions we want people working in.

MALE PHONE CALLER: For certain. Well --

MS. LUXTON: You're talking about radiation here.

MALE PHONE CALLER: Well, you know, this Don Miller and this whole gang out there, you know, each -- every one of them, again, I keep repeating the same thing. Criminal charges should be brought up against each and every one of them.

Mr. Fox, I don't know what the devil NRC is thinking about with this Mr. Fox. But that's the guy that

everybody's got to go after. He's known for many, many years exactly what's happening in that plant.

MS. LUXTON: But you know what? You see, the NR --

MALE PHONE CALLER: But you know what's happening? His -- his understudies are the ones that are -- that they're throwing hatchets at. You know what I'm saying?

MS. LUXTON: Yes, right, right.

MALE PHONE CALLER: You can't hold --

MR. VERDUN: Let me tell you a story about Mr. Fox, sir.

MALE PHONE CALLER: Pardon me?

MR. VERDUN: Let me tell you a story about Mr. Fox that probably a lot of listeners don't know, but a lot of the people at the plant do know about. One time as a young engineer, he was an engineer on Unit I.

MALE PHONE CALLER: Yes.

MR. VERDUN: So, he certainly knew or should have known about the refueling violations that were taking place with respect to the full-core off-load. It has been going on since day one.

And he was an engineer in Unit I Engineering. He was around that site. He was intimately familiar with that site for years before he began to progress up the

ladder.

MALE PHONE CALLER: Right.

MR. VERDUN: And incidentally, Bob Bush just got fired because of his attitude towards employees primarily I believe, and his arrogant attitude towards employees, and the fact that he was nothing but a -- a bully that pushed his weight around and --

MALE PHONE CALLER: I knew Bob Bush, sure.

MR. VERDUN: -- and basically exerting -- exerted his -- his influence to put people in situations where they took risks with safety, in my opinion.

MALE PHONE CALLER: Yes.

MR. VERDUN: Mr. Fox condoned that behavior from the beginning. He was Mr. Bush's boss.

MALE PHONE CALLER: Yes.

MR. VERDUN: That guy needs to go.

MALE PHONE CALLER: Oh yes.

MR. VERDUN: They need to get him out of there fast.

MALE PHONE CALLER: He needed a muscle-man out there to look good with the stockholders. That's exactly what it amounted to. And again, that situation you're talking about, the tank that you saw the sludge, high radiation sludge, and so on, that goes on in I, II, and III all the time, you know?

And again, it's the dollar over the safety. You know what I'm saying?

MS. LUXTON: Yes. Thank you, sir. I'm going to -- I'm going to go to the next caller, okay?

MALE PHONE CALLER: My pleasure.

MS. LUXTON: Thanks so much for calling.

MALE PHONE CALLER: Right.

MS. LUXTON: It was great to hear from you. Wow, how about that, a confirmation of -- we've heard this before.

MR. VERDUN: Well, it's kind of a confirmation of what the employees in the -- in the rad waste facility told me when I was down there, that they didn't feel comfortable about working under those conditions.

MS. LUXTON: Yes.

MR. VERDUN: They had grown kind of complacent about it and realizing there was nothing they could really do to change the situation --

MS. LUXTON: Yes.

MR. VERDUN: -- by themselves. So, they were kind of reaching out to me --

MS. LUXTON: What a shame.

MR. VERDUN: -- to help them.

MS. LUXTON: What a shame. Unfortunately --

MR. VERDUN: And so I tried to do --

MS. LUXTON: Unfortunately, you were cut off before you could. Okay, let's go on. Now, we -- we wanted to ask other employees to call if they could because you'd like to do a support group, right --

MR. VERDUN: Absolutely.

MS. LUXTON: -- for the terminated -- for the people who were terminated?

MR. VERDUN: Right. One of the primary reasons why I'm here tonight is I want to try to get the word out to the 104 people that were terminated --

(Telephone ringing).

MR. VERDUN: -- on January 11th to get in touch with us somehow through either getting in touch with you or calling me directly so we can get a support --

MS. LUXTON: Do you want to give your number?

MR. VERDUN: -- group going. My home phone number is (860) 442-6339. You can call me, tell me your story. And we need to get a big database going so we can get probably a class action lawsuit going against these people.

MS. LUXTON: Good.

(Dial tone).

MS. LUXTON: Uh-oh. Hi, did I lose it? You know, I've been doing very well with the phone for the last few weeks.

MR. VERDUN: (Laughing).

MS. LUXTON: I really have.

MR. VERDUN: Yes.

MS. LUXTON: I think I lost you. Please call back. I'm sorry. I thought I was -- oh no, I think I pushed -- wait a minute. Hello?

MALE PHONE CALLER: Yes, hello.

MS. LUXTON: Oh, I'm sorry. I thought I'd lost you. Gee, I saved myself here. How you doing?

MALE PHONE CALLER: Okay, thank you. Good evening.

MS. LUXTON: Good evening. What's on your mind?

MALE PHONE CALLER: Just an easy question.

MS. LUXTON: Yes.

MALE PHONE CALLER: Any -- any chance the Millstone could be shut down forever, and to make the -- safe?

MS. LUXTON: Who wants to take that? Do you want to take --

MR. VERDUN: I'll take that one. I don't think -- I don't want to see Millstone -- Millstone shut down forever. And Susan doesn't want to see Millstone shut down forever either.

MS. LUXTON: I don't? Wait a minute, now.

MR. VERDUN: Well --

MS. LUXTON: Speak for yourself, Gary.

MR. VERDUN: Ah, well --

MS. LUXTON: You go first --

MR. VERDUN: Okay.

MS. LUXTON: -- and then I'll go.

MR. VERDUN: I'll -- I'll speak for myself. I don't want to see Millstone shut down forever. What I want to see is I want to see Millstone adhering to the letter of the law. I'd want to -- I don't want to see these people breaking federal laws.

I don't want to see them discriminating against employees. I don't want to see them breaking Department of Labor laws. I don't want to see them challenging every single law and every single issue that -- that comes up and trying to push it to the maximum --

MS. LUXTON: Yes.

MR. VERDUN: -- and stretch everything to the limit.

MS. LUXTON: Yes.

MR. VERDUN: That's the kind of situation that got them in this situation. That's the kind of thing that led to the current situation. They have no credibility with the community. They have no credibility with the NRC.

They have to no credibility with any of the people that were terminated. They have no credibility with their own employees because their own employees see what's happening to other people, and they know that it's probably not too long before they're going to get the same kind of treatment.

MS. LUXTON: Yes.

MR. VERDUN: They have no credibility with their stockholders, and they shouldn't have any credibility at this point with their Board of Directors.

But for some reason, upper level management still seems to have retained some kind of credibility with the Board of Directors. That -- that's something that's beyond my ability to comprehend.

The Board of Directors needs to flush these guys out, find out who the people are that have been forcing the company into this situation, got them into this embarrassing situation with all these violations of federal laws, state laws, employment laws.

They've got -- Board of Directors, you've got to get these people out of here. Because if you don't, all the stockholders in your company are going to lose their shirts. That stock won't be worth --

MS. LUXTON: Even more than they have, right?

MR. VERDUN: -- two cents --

MALE PHONE CALLER: Excuse me, but --

MR. VERDUN: when these people are done with you.

(End of Tape 1, Side A.)

(Start of Tape 1, Side B.)

MALE PHONE CALLER: You're probably right, Mr. Gary. I shut up.

MS. LUXTON: You know what?

MR. VERDUN: No, you're still on.

MS. LUXTON: It's --

MALE PHONE CALLER: Yes, please. The gentleman there, Mr. Gary, is absolutely right. But this -- another question. I've got the family here. They can't sleep, you know, at night just think about what's going on over there. A ot of people they're moving out from Waterford.

MS. LUXTON: Hmmm.

MALE PHONE CALLER: They say how -- you know, you cannot trust anymore I'm surprised the -- the government, Mr. Roland get involved more, no?

MS. LUXTON: I'm surprised also.

MALE PHONE CALLER: I know. I mean --

MR. VERDUN: I think everybody is very surprised with Mr. Roland's stand on this issue. He came to Millstone one day and spent a couple of hours here, did

a cursory inspection of the site, and then made some pronouncement -- pronouncement that he thought the site was safe, and left.

I mean, I think that that basically was --

MS. LUXTON: Irresponsible.

MR. VERDUN: -- totally irresponsible on the part of the government.

MALE PHONE CALLER: Yes.

MR. VERDUN: He's not looking or listening or reading or hearing what's actually happened down here --

MS. LUXTON: Right.

MR. VERDUN: -- at the site. If you're listening, Mr. Governor, if you'd care to give me a call, I'd be more than happy to take a couple of minutes of my time and talk to you about this. I do have a pretty busy schedule, but I think I could fit you in.

MS. LUXTON: (Laughter.) Thanks so much for calling, sir.

MALE PHONE CALLER: Thank you, Susan. Good night.

MS. LUXTON: Good night. Well, you know, getting back to what I think about it, it's not that I want to see them shut down forever. But if they can't run safely, I definitely don't think they should start up until we can be convinced they do.

I think I'd feel a lot better if they weren't here at all. But I think we, as a state, have to start looking to alternatives to nuclear energy. We're so dependent on them.

And I think it's wonderful that Mr. Blumenthal came out with this whole deregulation: all the information on deregulation, making it known to the public, step by step of the way, because that's looming on the horizon. We're going to have a show on that too. But, let's go on.

MR. VERDUN: Susan, I'd like to interject one thing --

MS. LUXTON: Go ahead.

MR. VERDUN: -- before you go on to the next issue.

MS. LUXTON: You can interject anything, Gary.

MR. VERDUN: We've -- we have -- we've forgotten about 13 other very important people --

MS. LUXTON: Yes.

MR. VERDUN: -- in this process, and those are 13 people that were working for me in 1994 --

MS. LUXTON: Yes.

MR. VERDUN: -- early in 1994, that were also terminated at Millstone. There are 13 housekeepers that were terminated in early 1994, and they were also

subjected to the same kind of a process that this 104 were.

There's really not 104 people's livelihoods that are at stake here. It's a 117.

MS. LUXTON: Seventeen.

MR. VERDUN: So if any of the 13 people working for me that were terminated by the company, and without my knowledge incidentally or my approval, without any discussions with me whatsoever, I'd like to have those 13 people also get in touch with me because I want to try to get them included in this support group.

The sooner we can take this thing with a -- some kind of a class action or law suit, but we need to work together on this as a united effort to have the greatest impact.

MS. LUXTON: Oh, that's great, Gary. Good for you. Good for you. All right, let's talk about what was in the news today. Now, we had two articles in *The New London Day* today. One at the bottom of *The New London Day* was "NRC advising quick evacuation in the event of a nuclear accident." Well, isn't it about time they got around to doing that? Two miles out, they want them evacuated immediately.

But they said they've found that people evacuate up to 50 miles out, Gary, up to 50 miles out

because like Mr. Sheridan said to us once with the emergency evacuation plan, "If they find out the wind is going a certain way, they'll evacuate that neighborhood."

MR. VERDUN: Because that's --

(Telephone ringing).

MR. VERDUN: -- where the plume -- that's where the radioaction goes.

MS. LUXTON: Right where the plume is going. But so I'm -- I'm right on the border of that neighborhood. And I see everybody over there going, right, and I'm --

MR. VERDUN: Yes.

MS. LUXTON: -- supposed to sit here and think, "Well," --

MR. VERDUN: (Laughing).

MS. LUXTON: -- "okay, no problem. I think I'll have a cup of iced tea."

MR. VERDUN: (Laughing).

MS. LUXTON: Forget it, they all move out.

MR. VERDUN: Yes.

MS. LUXTON: It's ridiculous, the evacuation plan. Let's see if I can get these people.

(Dial tone).

MS. LUXTON: Oh my God. Hi, you're on Nuclear Safety Issues.

FEMALE PHONE CALLER: Hello?

MS. LUXTON: Hi.

FEMALE PHONE CALLER: Hi, I have a question for Gary.

MS. LUXTON: Sure.

FEMALE PHONE CALLER: Why did he wait 16 years waiting to get laid-off? Why didn't he leave before that if it was so unsafe?

MR. VERDUN: I did not say that the plant was unsafe for 16 years. I said that the plant began to degrade in 1987, and that -- and that by -- by 19 -- because of budget cuts and because of management attitude, the arrogance of the management towards their employees, that because of nuclear safety concerns that came along, the site began to degrade.

It degraded in steps. In 1987, it was a world-class nuclear power plant. And there were a lot of proud people working there. And certainly -- and incidentally, there are a lot of proud people working there today.

Most -- almost all of my friends in my life worked there, the majority of my friends. They're highly specialized, highly technical, highly educated people, and they're real professionals.

But the problem is when -- when this

management regime came in, the new management regime came in, they began to drag this site down with them. And they created -- they took a world-class performing nuclear power plant -- it became a level two plant.

And then recently, it became a level three, troubled plant. So, this -- this wasn't a situation that existed for my whole career. And I have been very proud to say that I worked for Northeast Utilities for many of those years.

MS. LUXTON: Ma'am, I think you're under the mis -- the misimpression that Gary didn't move. Gary got terminated. He didn't lay himself off. They --

FEMALE PHONE CALLER: I understand that.

MS. LUXTON: Okay, okay.

MR. VERDUN: Does that answer your question, ma'am?

FEMALE PHONE CALLER: I guess so, thanks.

MR. VERDUN: You're welcome.

MS. LUXTON: Okay, we have five minutes left. Okay, there was another article in the paper today saying that we've got a full commission now, Gary. Did you know that?

MR. VERDUN: Yes.

MS. LUXTON: The NRC now has two new commissioners.

MR. VERDUN: I read that in the paper this morning.

MS. LUXTON: Both -- they -- they have to be confirmed by the Senate, but this is good I think.

MR. VERDUN: Yes.

MS. LUXTON: The more commissioners, the better.

MR. VERDUN: Yes.

MS. LUXTON: I mean, now they're working with a full board.

MR. VERDUN: That's right.

MS. LUXTON: So, that's good.

MR. VERDUN: They now have a full deck again.

MS. LUXTON: Full deck. Hey, we didn't talk about -- hey, let's talk about that funny thing that we were going to talk about, Gary, that I had forgotten about the --

(Phone ringing).

MS. LUXTON: -- the Northville Mountain Team --

MR. VERDUN: Oh, yes.

MS. LUXTON: -- the team building fiasco.

MR. VERDUN: Yes.

MS. LUXTON: That's funny. Okay, hi, you're on Nuclear Safety Issues.

FEMALE PHONE CALLER: Yes, I have a real

serious concern here that I would love to know how you could be such experts on this if you can't even pronounce "nuclear" properly. It's not "nucular," and that really gets to me for you people to come across as if you're experts. Do consider practicing saying "nuclear."

MS. LUXTON: Ma'am?

FEMALE PHONE CALLER: Yes.

MS. LUXTON: I never said I was an expert.

FEMALE PHONE CALLER: Well, you're sure sounding like you're talking about you have all the best interests of all of us in our hearts.

MS. LUXTON: Well, I -- I have my own best interest at heart and my family's best interests at heart and I hope --

FEMALE PHONE CALLER: Well --

MS. LUXTON: -- you do too.

FEMALE PHONE CALLER: -- it's very interesting when all these discussions with people who have created a situation where the industry has to lay people off is now shocked that they're laying them off.

So I mean, let's -- you're creating something. Let's deal with it, and not get too uptight about it. But do please practice saying "nuclear," would you?

MR. VERDUN: Thank you for your call, ma'am.

FEMALE PHONE CALLER: Do you think you can

handle that? "Nuclear" is the way it's pronounced, not "nucular."

MS. LUXTON: Thank you, ma'am.

FEMALE PHONE CALLER: Thank you.

MR. VERDUN: Thank you for your call, ma'am.

MS. LUXTON: Hmmm, that was interesting. Are we the disgruntled employees that made the situation?

MR. VERDUN: No, I -- I was never a disgruntled employee. I was a loyal employee for the company. I did my job. I played by the rules. I was terminated by the company.

Now, I'm an -- I'm a former employee. I'm here to tell you things that people that work at Northeast Utilities are really not free to say without fear of reprisal.

(Phone ringing).

MS. LUXTON: Hi, you're on Nuclear Safety Issues.

FEMALE PHONE CALLER: Hi, I've been told to hurry, so I will. But ever since the day President Carter pronounced it "nucular," I've been thinking that "nuclear" was the proper pronunciation. But I looked it up in the dictionary, and both pronunciations are accepted.

So, even though you don't know your "nuclear" stuff --

MR. VERDUN: (Laughing).

FEMALE PHONE CALLER: -- you are pronouncing it correctly.

MS. LUXTON: Well, thank you, ma'am.

MR. VERDUN: Thank you very much, ma'am.

FEMALE PHONE CALLER: Bye-bye.

MS. LUXTON: Bye.

MR. VERDUN: Was that the same lady?

MS. LUXTON: No, that was a different lady.

MR. VERDUN: Oh, okay.

MS. LUXTON: But --

(Dial tone).

MS. LUXTON: -- I don't care how I pronounce it, to tell you the truth. The point is "nuclear," "nucular," I could have a little twang in it. I might come from Texas and say "nuclea" or someplace like that.

MR. VERDUN: (Laughing).

MS. LUXTON: The point is you understand the word I'm saying I hope, okay? Northville Mountain, we're not going to get a chance to talk about that.

MR. VERDUN: Well, we --

MS. LUXTON: We have about one minute left.

MR. VERDUN: Oh, one minute?

MS. LUXTON: Right, Mary, one minute left? Yes, we won't be able to talk about it. We're going to

have to --

MR. VERDUN: Well, we can talk about that on another show.

MS. LUXTON: We can -- right, right. Okay, I want to just give a couple -- an update of a couple of things that are coming up.

(Phone ringing).

MS. LUXTON: Why are you giving me another call if we only have one minute left?

(Dial tone).

MS. LUXTON: Hi, this has to be quick if you want to have a question.

MALE PHONE CALLER: Yes, I have a beautiful request to you and to the fellow next to you.

MS. LUXTON: Yes.

MALE PHONE CALLER: Why do you have so much talk and the -- no do the job once and for all? You do it the -- in this situation, they cannot operate anymore at this particular nuclear location plant. So, I hope they do something now, not too much talk.

I read that paper, I read the -- the subject. I read the --. They still hire these people. Why they not be prosecuted?

MS. LUXTON: Thank you, sir. I agree completely. Bye.

MALE PHONE CALLER: Bye.

MS. LUXTON: Okay, folks, meeting coming up on September 11th, Dr. Jay Gould, Jordan Firehouse at 7:30. It's a CRC lecture series. We're going to be talking about cancer in our community and around nuclear power plants. Thank you, Gary, for being here.

MR. VERDUN: Thank you very much, Susan.

MS. LUXTON: We have -- thanks so much.

MR. VERDUN: It's a pleasure to be here.

MS. LUXTON: Come back again, okay?

MR. VERDUN: I think you do a very good service for this community.

MS. LUXTON: Thanks.

MR. VERDUN: It's a pleasure.

MS. LUXTON: You too, thanks.

MR. VERDUN: Thank you.

MS. LUXTON: See you next week, folks.

(Closing music.)

(End of Tape 1, Side B.)

C E R T I F I C A T E

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Connecticut Public Television Broadcast re Nuclear Safety Issues on August 2[illegible], 1996

Docket Number: (not applicable)

Place of Proceeding: Television Broadcast

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Lauri Ward

Lauri Ward

ACTION

EDO Principal Correspondence Control

FROM: DUE: ~~12/31/96~~ 01/21/97 EDO CONTROL: G960919
DOC DT: 11/25/96
FINAL REPLY:

Deborah Booth Katz
Citizens Awareness Network

TO:

Emile Julian, DSB

FOR SIGNATURE OF : ** GRN ** CRC NO: 96-1189

DESC: ROUTING:

2.206 PETITION ON CONNECTICUT YANKEE, MILLSTONE UNITS 1, 2, AND 3

Taylor
Milhoan
Thompson
Blaha
Miraglia, NRR
HMiller, RI
Lieberman, OE

DATE: 12/06/96

ASSIGNED TO: CONTACT:

OGC Cyr

SPECIAL INSTRUCTIONS OR REMARKS:

NRR RECEIVED: DECEMBER 16, 1996
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NRR ROUTING: MIRAGLIA
THADANI
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TRAVERS
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ACTION
DUE TO NRR DIRECTOR'S OFFICE
BY ~~Dec. 26, 1996~~

Extended to 01/16/97 per Patty Travalas

OGC-96- 005082

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PAPER NUMBER: CRC-96-1189 LOGGING DATE: Nov 29 96

ACTION OFFICE: EDO

AUTHOR: DEBORAH KATZ
AFFILIATION: MAINE

ADDRESSEE: EMILE JULIAN, SECY

LETTER DATE: Nov 25 96 FILE CODE: ID&R 5 MILLSTONE

SUBJECT: 10 CFR 2.206 PETITION ON CONNECTICUT YANKEE, MILLSTONE UNITS 1,2 & 3

ACTION: Appropriate

DISTRIBUTION: CHAIRMAN, COMRS, OGC, D&SB

SPECIAL HANDLING: NONE

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