U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.	50-271
Licensee No.	DPR-28
Report No.	97-08
Licensee:	Vermont Yankee Nuclear Power Corporation
Facility:	Vermont Yankee Nuclear Power Station
Location:	Vernon, Vermont
Dates:	September 7 - October 31, 1997
Inspectors:	William A. Cook, Senior Resident Inspector Edward C. Knutson, Resident Inspector Jason C. Jang, Engineer, Division of Reactor Safety (DRS) Robert J. Summers, Division of Reactor Projects William A. Maier, Engineer, DRS Kenneth S. Kolaczyk, Engineer, DRS Timothy L. Hoeg, Engineer, DRS Mark Holbrook, Contractor, INEL
Approved by:	Curtis J. Cowgill, III, Chief, Projects Branch 5 Division of Reactor Projects

EXECUTIVE SUMMARY

Vermont Yankee Nuclear Power Station
NRC Inspection Report 50-271/97-08

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a seven week period of resident inspection and includes results of announced inspections by regional specialist inspectors.

Operations

The inspector determined that the VY staff had responded appropriately to the September 27 seismic monitor alarm and that the declaration of an Unusual Event had been in accordance with their emergency procedures. However, the inspector considered that the timeliness of licensee action to address this previously observed overly conservative Emergency Plan entry condition, (single, unconfirmed seismic monitor alarm), to have been slow.

Inspector review of the October 10 ENS call, involving the Alternate Cooling System (ACS) cable separation issue, identified an appropriate immediate response to the ACS operability concern and appropriate follow-up corrective actions.

Maintenance

Based upon observation of a variety of maintenance and surveillance testing items, appropriate control and execution of these activities was noted.

The licensee identified and corrected reactor building ventilation radiation monitor testing discrepancy (LER 96-23) was not cited. The procedural non-compliance which contributed to the fuel oil sampling and analysis events discussed in LER 96-29 was not cited. The low pressure coolant injection surveillance testing discrepancy discussed in LER 96-27 was not cited.

Engineering

At the end of the inspection period, the VY staff had completed formal emergency diesel generator (EDG) support piping stress analyses and had completed a metallurgical analysis which VY believes supports their initial EDG operability determination. These items were under review by the NRC staff. Pending the results of further NRC staff review, the EDG support piping welds issue is being tracked as an inspector follow-up item **(IFI 97-08-01).** The licensee's response to this issue, to date, has been consistent with the guidance of Generic Letter 91-18.

VY established a program that met their commitments to GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." Final validation of switch settings is currently scheduled to be completed by January 30, 1998. Use of the Electric Power Research Institute (EPRI) motor operated valve performance prediction program to validate switch settings for essentially all MOV's was exceptional and considered to be a program strength.

The failure to have included and tested a number of keep fill system check valves in the VY Inservice Testing Program (reference LER 96-11) was not cited.

Plant Support

The radioactive liquid and gaseous effluent control programs were well implemented.

- The licensee implemented good management control and oversight of the quality of the radioactive liquid and gaseous effluent control programs.
- The effluent radiation monitoring system calibration program, including trending analysis, was well-implemented.
- The ventilation system surveillance program was well-implemented. However, the plant air balance measured in 1971 might be invalid, as described in Section R.2.3 of this inspection report. **(IFI 97-08-02)**
- Very good quality control for the chemistry laboratory and quality assurance audit programs were established.

The failure to have appropriately controlled the movement of reactor vessel shield blocks preceding the 1990 and 1992 refueling outages (reference LER 96-03 and URI 96-03-05) was not cited.

TABLE OF CONTENTS

Report Details

Summary of Plant Status

During this inspection period, Vermont Yankee (VY) operated at full power with the exception of power reductions to conduct planned surveillance testing.

A region based specialist inspector was on site the week of September 22 to examine VY's radioactive liquid and gaseous effluent control programs. The results of that inspection have been integrated into this report.

A region based specialist inspector was on site the week of September 29 to conduct a follow-up inspection of the Architect/Engineering Design Inspection (report No. 50-271/97-201) findings. The results of that follow-up inspection will be documented in inspection report No. 50-271/97-10.

During the week of October 13, region based specialist inspectors conducted a follow-up inspection of the motor-operated valve program developed in accordance with Generic Letter 89-10.

On October 6, the inspectors were provided an overview of the licensee's Human Performance Improvement Program which has the goals of: achieving excellence in human performance; achieve a reduction in error rate; and achieve an improved rating in human error probability index. This program was initiated, in part, in response to recent Notices of Violation (refer to inspection reports 97-04 and 97-05) citing poor human performance and, in part, to a licensee recognized adverse trend in this area. Training sessions with small groups of the plant staff were scheduled to commence later in the month.

I. Operations

O1 Conduct of Operations[1] (93702)

O1.1 Unusual Event Declared Due to Indication of Possible Seismic Event

a. Inspection Scope (71707)

The inspector examined the licensee's response to a seismic monitor alarm and the basis of their decision to declare an Unusual Event.

b. Observations and Findings

At 9:08 pm on September 27, the plant seismic monitor alarmed. Control room operators were alerted to the event via the seismic monitor main control board annunciator. There were no other indications that a seismic event (earthquake) had occurred. The licensee declared an Unusual Event (UE) based on emergency procedure AP-3125, "Emergency Plan Classification and Action Level Scheme,"

---

[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

entry criteria U-5-c, "Any earthquake sensed on-site as recognized by observation or detection." The states of Vermont and New Hampshire and the Commonwealth of Massachusetts were notified and a one-hour emergency notification system (ENS 33001) call was made to the NRC, as required by 10 CFR 50.72.

The inspector observed that the VY staff properly responded in accordance with operating procedure OP-3127, "Natural Phenomena." This included visual inspection of selected plant structures for possible damage and the completion of a seismic damage indicator walkdown. No evidence of earthquake damage was observed. Given that no other monitoring stations had detected an earthquake and that a preliminary investigation of the seismic monitor identified an internal failure, the licensee declared the seismic monitor inoperable and terminated the UE at 11:10 p.m. Subsequent troubleshooting of the seismic monitor identified that the monitor battery had failed, which caused the electrical transient that resulted in the monitor alarm.

On May 31, 1997, a malfunction of the seismic monitor had also resulted in the declaration of an UE. As discussed in inspection report 50-271/97-04, the inspector observed that the procedural requirement to declare an UE based upon a single indicator was overly conservative. Accordingly, allowance to verify that a seismic event has actually occurred, prior to making an Emergency Plan event declaration, would potentially avoid the unnecessary mobilization of state and NRC emergency response organizations. In light of the September 27 occurrence, the inspector considered that the licensee has been slow to address this procedural requirement. The inspector determined that procedure revisions were being processed at the time of the September 27 event, which were designed to provide for a seismic event verification, if appropriate, prior to Emergency Plan entry.

c. Conclusions

The inspector determined that the VY staff had responded appropriately to the September 27 seismic monitor alarm and that the declaration of an Unusual Event had been in accordance with their emergency procedures. However, the inspector considered that the timeliness of licensee action to address the previously identified Emergency Plan entry condition problem, (single, unconfirmed seismic monitor alarm), to have been slow.

O1.2 10 CFR 50.72 Notification Involving Inadequate Cable Separation of the Alternate Cooling System

At 7:57 pm on October 10, the control room operators notified the Headquarters Duty Officer (Event No. 33070) in accordance with 10 CFR 50.72, that a condition outside the plant's Updated Final Safety Analysis Report (UFSAR) had been identified involving power cable separation of Alternate Cooling System (ACS) cooling tower fan No. 2-1. Specifically, the two emergency power feeds, one from motor control center (MCC) 8C (safety related Division I) and one from MCC 9C (Division II), were not properly separated per the UFSAR and Vermont Yankee Specification VYS-027 electrical separation criteria. The No. 2-1 fan is normally powered via a non-safety related MCC (MCC-5B2A). To address the immediate operability concern, the licensee tagged open both safety related power supply breakers (MCC 8C, breaker 2C is normally closed) and the seven-day limiting condition for operation (LCO) was entered, in accordance with ACS Technical Specification (TS) 3.5.D.3, pending further review.

Inspector follow-up determined that the licensee revised the ACS operating procedure to maintain both of the cooling tower fan No. 2-1 safety related breakers normally open and provided amplifying instructions for operators to closed the breakers in the event that the alternate cooling tower fan was needed. The inspector reviewed the safety evaluation (Safety Evaluation No. 97-28) supporting the procedure changes to OP-2181, OP-2143, and OT-3122, and found the licensee's assessment of the changes consistent with 10 CFR 50.59 requirements. The inspector also observed the Plant Operations Review Committee's deliberation and approval of SE No. 97-28 and concluded their safety review was appropriate. The licensee satisfactorily implemented the procedure changes and exited the TS LCO on October 16.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) LER 97-11: The primary containment torus was not inerted to Technical Specifications requirements due to an inadequate procedure which resulted in an insufficient nitrogen inerting purge flowrate.

LER 97-11, dated June 11, 1997, was previously reviewed by the inspectors, as documented in inspection report 97-05, section O1.2. As a result of this event, a Notice of Violation (**VIO 97-05-01**) was issued citing the non-compliance with Technical Specification 3.7.A.7.b. Inspector review of the licensee's response, dated September 18, 1997, and any additional corrective action verification will be tracked via **VIO 97-05-01**. LER 97-11 is closed.

O8.2 (Closed) LER 97-14: Lack of understanding of plant licensing and design bases results in an inadequate response to industry operating experience which allowed resumption of plant operations inconsistent with its design basis.

LER 97-14, dated September 5, 1997, was previously reviewed by the inspectors, as documented in inspection report 97-06, section E.8.2. As a result of this event, a Notice of Violation (**VIO 97-06-03**) was issued citing ineffective corrective action. Inspector review of licensee's response, dated October 1, 1997, and any additional corrective actions verifications will be tracked via **VIO 97-06-03**. LER 97-14 is closed.

O8.3 (Closed) LER 97-17: An equipment malfunction remaining undetected by the operating crew results in plant operation in excess of rated thermal power.

LER 97-17, dated October 2, 1997, documented the licensee's assessment and corrective actions for the violation of the reactor thermal power limit which occurred on September 2, 1997, due to a plant process computer data acquisition system component failure. This event was previously reviewed by the inspectors and documented in inspection report 97-06, section O1.2. As stated in report 97-06, this non-compliance with the VY thermal power limit was non-cited, consistent with section VII.B.1 of the NRC Enforcement Policy. The inspector determined that LER 97-17 clearly and concisely described the circumstances involving this event and that the action taken by the VY staff to correct the problem and preclude a recurrence were appropriate and well documented. LER 97-17 is closed.

O8.4 (Closed) LER 97-12: Residual heat removal service water flow could be potentially less than the design basis flow due to instrument inaccuracies.

This event was previously discussed in inspection report 97-04, section E.7.1 and assigned an inspection follow item (**IFI 97-04-04**). The root cause for this event remains under investigation. However, a Basis for Maintaining Operation (BMO) No. 97-27, dated June 13, 1997, was initiated to summarize the residual heat removal (RHR) service water system operability assessment and document the corrective action plan. The inspector reviewed the licensee's interim corrective actions and found them to be appropriate. Adequate RHR service water system cooling capacity was demonstrated, via analysis, provided river water temperature remained equal to or less than 80 degrees F (revised from the May 2, 1997 limit of 70 degrees F). As of the conclusion of this inspection period, BMO No. 97-27 was still in effect.

LER No. 97-12 is closed. However, the licensee's actions to resolve this issue will continue to be tracked via **IFI 97-04-04**. The inspector notes that the broader issue of instrumentation accuracy was identified as a concern in inspection report 97-201 (reference section E.2.2.2.f, **URI 97-201-16**) and will be tracked separately.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Observations

a. Inspection Scope (62707)

The inspectors observed portions of plant maintenance activities to verify that the correct parts and tools were utilized, the applicable industry code and Technical Specification requirements were satisfied, adequate measures were in place to ensure personnel safety and prevent damage to plant structures, systems, and components, and to ensure that equipment operability was verified upon completion of post-maintenance testing.

b. Observations, Findings, and Conclusions

The inspector observed all or portions of the following maintenance activities:

- Preventive maintenance to MCC 10C, on September 30.
- Scram solenoid pilot valve replacements (18-31, 22-43, and 38-27), on September 12.
- 'A' emergency diesel generator lubricating oil piping replacement, on October 23.
- Scram solenoid pilot valve replacement and single rod scram time testing on October 20 and 21.

The inspectors observed proper adherence to procedure and appropriate control and execution of the above activities.

M1.2 Surveillance Observations

a. Inspection Scope (61726)

The inspectors observed portions of surveillance tests to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to limiting condition for operations (LCOs), and correct post-test system restoration.

b. Observations, Findings, and Conclusions

The inspector observed all or portions of the following surveillance tests:

- Core spray system quarterly surveillance test, observed October 7.
- 'B' emergency diesel generator monthly testing, observed on September 22.

The inspectors observed proper adherence to procedure and appropriate control and execution of the above activities.

M8 Miscellaneous Maintenance Issues (92700, 92903)

M8.1 (Closed) LER 96-23 and NCV 97-08-03: Inadequate surveillance procedure results in failure to meet Technical Specification requirements for radiation monitor functional testing.

LER 96-23, dated October 15, 1996, documented a licensee identified logic system functional testing deficiency discovered during the biennial review of procedure OP-4326, "Reactor building ventilation and refueling floor radiation monitors functional/calibration." After identification of the testing oversight and revision of the surveillance procedure, the radiation monitors' high alarm output contacts, previously not verified to actuate, were tested satisfactorily. Consequently, although OP-4326 did not satisfy the Technical Specification functional testing requirements (per TS Table 4.2.3), the radiation monitors were demonstrated to function, as designed. This non-repetitive, licensee identified and corrected violation was treated as a non-cited violation **(NCV 97-08-03)**, consistent with Section VII.B.1 of the NRC Enforcement Policy.

The inspector noted that concurrent with this event, the VY staff was conducting a re-evaluation of their logic system functional test (LSFT) procedures in accordance with their April 18, 1996 response to Generic Letter (GL) 96-01. By letter dated September 20, 1997, VY revised their August 31, 1997 commitment to complete GL 96-01 actions by February 28, 1998. Inspector review of the licensee's completed LSFT actions is being tracked by **IFI 97-06-01** (reference inspection report 97-06, section M1.5). LER 96-23 is closed.

M8.2 (Closed) LER 96-29 and NCV 97-08-04: Process and communication inadequacies result in the failure to analyze emergency diesel generator fuel oil within time allotted by Technical Specification surveillance requirements.

This LER was previously discussed in Section R8.2 of NRC Inspection Report 50-271/96-11. The NRC concluded in that inspection report that the licensee's description of the reported violation of plant Technical Specification (TS) surveillance requirements was incorrect, in that the licensee erroneously assumed that the diesel generator fuel oil sampling and quality verification surveillance requirement (TS 4.10.C.2) had two separate surveillance intervals, one for the act of sampling the fuel oil and another for the analysis of the sample (quality verification).

In this inspection period, further NRC follow up of this LER and the associated requirements identified additional findings and a necessary clarification to the prior inspection report discussion. The prior inspection findings included a statement that "this TS requires the fuel oil to be sampled every 30 days and implies that the sample should be analyzed prior to the next 30-day sample being taken." Upon further review, the NRC recognized that the actual requirement of the VY TS was based on a "once a month" requirement and not "30 days" as stated in inspection report 50-271/96-11. While this difference does not change the overall NRC conclusion that no violation of the TS occurred, the interpretation of the requirement in the previous inspection report was not completely accurate. To clarify, the NRC determined that TS 4.10.C.2 requires the diesel generator fuel oil to be sampled once a month. Implied with this requirement is that the sample analysis be completed prior to the next monthly sampling activity. While noting that there are various interpretations of "once a month," the NRC concludes this could be as long as 31 days or as short as 28 days. For example, if the surveillance is conducted on the 15th of the month, the next surveillance would be due on the 15th of the next month. In addition, the NRC noted that the surveillance interval could be extended by a plus 25 percent, in accordance with the licensee's TS definition for surveillance frequency.

The inspector reviewed the licensee's internal event report documentation for this issue and determined that once identified, the concern was appropriately handled by station personnel. Based on the fact that the analyses results were already known to be acceptable, albeit late, and since the fuel oil quality integrity had been maintained appropriately throughout, the licensee concluded that the emergency diesel generators were unaffected by this event. Based on the review of the licensee's analysis at the time of the event, the inspector agreed that the emergency diesel generators remained operable.

As outlined in the discussion above, the NRC concluded that no technical specification violation occurred as stated in the LER. Upon review of the timing of the sampling and analysis of the diesel fuel oil contained in the LER, the inspector determined that the surveillance requirements were met. However, the NRC concluded that the licensee failed to implement station procedures used to schedule and track the timely completion of important-to-safety activities, like TS required surveillance tests. The failure to properly implement the associated station procedures was a violation. The licensee's corrective actions described in the LER were determined appropriate to correct this procedure violation. This non-repetitive, licensee identified and corrected violation was treated as a non-cited violation **(NCV 97-08-04)**, consistent with Section VII.B.1 of the NRC Enforcement Policy.

M8.3 (Closed) LER 96-24 and IFI 96-09-01: Incomplete design bases documentation results in a failure to clearly describe Appendix J methodology in the program description delivered to the NRC for evaluation.

On October 2, 1996, the VY staff notified the NRC staff that an engineering evaluation had concluded that the lack of closure capability of the motor-operated core spray minimum flow valves (CS-5A and 5B) was a condition outside the plant design basis. The licensee had determined that the valve wiring and logic prohibited minimum flow valve closure unless the core spray pump was running with injection flow. This valve logic and wiring condition resulted in the inability to close the minimum flow valves for containment isolation purposes. At that time, the licensee modified the core spray minimum flow valve logic to permit valve closure from the control room.

The inspector reviewed the licensee's evaluation of this event and corrective actions. The licensee's evaluation considered various aspects of the plant's design and licensing bases and resulted in clearly determining that the original design basis for this system did not require the minimum flow valves to be containment isolation valves. That portion of the system was required to open for accident purposes and was considered an extension of the containment boundary. This position was also clearly reflected in the licensee's response to the TMI Action Plan for containment isolation dependability, as stated in a licensee letter to the NRC on January 8, 1980. At that time, the core spray system was identified as one of a number of systems that communicated directly with the containment space without an automatic isolation valve. The licensee implemented routine inspections of the associated piping as a means for ensuring the integrity of the containment boundary. The licensee's evaluation noted that the conflicting information between the design and licensing bases regarding containment isolation capability for the CS mini-flow valves resulted from an incomplete review of the FSAR requirements for these particular valves. That resulted in an error translation into the Appendix J mini-flow valves resulted from an incomplete review of the FSAR requirements for these particular valves. That resulted in an error translation into the Appendix J program. The licensee's corrective actions appropriately addressed the causes of the design bases documentation error. Further, as a result of the licensee's review, they modified the controls design for these valves in order to enhance the operator's capability to ensure containment isolation by installing a remote manual isolation function.

The inspector concluded that the licensee's evaluation, root cause determination and corrective actions were acceptable. In that the design bases of the plant was accurate, and that the as-built configuration met the design basis, this condition was not a violation of NRC requirements. The licensee's action to modify the plant configuration to provide an enhanced operator control for containment isolation function was viewed as a positive measure. LER 96-024 is closed.

M8.4 (Closed) LER 96-27 and NCV 97-08-05: Lack of required verifications results in inconsistency between technical specification instrument setting description and the as-built configuration of the low pressure coolant injection (LPCI) pump control logic.

This LER describes the licensee's discovery of use of a time delay relay with a setpoint inconsistent with the TSs while testing the LPCI system actuation logic during the refueling outage in October 1996.

The time delay relay minimum time delay setting was 0.55 seconds for LPCI pump start and the plant TS required no time delay for two affected LPCI pumps. The licensee determined that the installed time delay relays were consistent with the materials used since initial plant startup and that the plant TS requirements (TS 7.4.3.5.2) have also not changed since initial plant startup. Therefore, this inconsistency between the as-built design and the TSs always been present. Due to the age of the issue, the licensee was not able to determine an actual root cause. However, the apparent cause was an inadequate verification of the license requirements versus the system design specifications during the development of the TSs. The licensee replaced the time delay relays with a modified design to permit instantaneous starts of the affected LPCI pumps. This corrected the inconsistency. Further, the licensee was already implementing a major Technical Specification improvement project that would result in verifying that the TSs and as-built design criteria were consistent.

The inspector concluded that the licensee's assessment, root cause determination, and corrective actions for this event were appropriate. However, failing to ensure that the LPCI surveillance tests met the acceptance criteria stated in the TSs was a violation of the TS. This non-repetitive, licensee identified and corrected violation was treated as a non-cited violation **(NCV 97-08-05)**, consistent with Section VII.B.1 of the NRC Enforcement Policy.

III. Engineering

E1 Engineering Support of Facilities and Equipment

E1.1 Safety Grade Qualification of Welds in Emergency Diesel Generator Support Systems

a. Background and Inspection Scope (93702,92903,37551)

The inspector observed and assessed the licensee's response to an industry event at Millstone, involving safety class support systems (such as the jacket water cooling and lubricating oil systems) that had been fabricated and installed as part of the EDG unit by Fairbanks Morse which were apparently not welded to ANSI B31.1 standards or an equivalent.

b. Observations and Findings

On September 4, the inspector discussed the EDG subsystems weld issue with VY systems engineering staff. The inspector was informed that VY had received information about the problem and would be investigating. The inspector visually examined piping welds in the EDG lubricating oil and jacket water cooling systems. The inspector observed that there was a strong possibility that the VY EDG subsystem piping had likewise not been welded to ANSI B31.1. The inspector observed that the welds had not been ground smooth to support any form of non-destructive testing, and areas of concavity existed in some welds. Due to the potential operability impact on both EDGs, the inspector promptly discussed this issue and his preliminary observations with the plant manager.

On September 10, Event Report (ER) No. 97-1224 was generated which addressed the potential weld problem with the EDGs. The immediate operability determination was that the EDGs were operable, based on the vendor's conclusion that the Millstone EDGs' piping welds had been found to satisfy Northeast Utilities' Millstone Unit 2 seismic analysis, and based on a walkdown by engineering personnel who judged the welds to be satisfactory by visual examination. ER 97-1224 was reviewed by plant management during the September 11 ER screening meeting. Initially, VY did not consider the Millstone problem to be an immediate concern because their procurement specifications had been different than Millstone. Specifically, Millstone had purchased the EDGs and done their own seismic analysis, whereas VY had specified in the procurement specifications that the EDGs were to be fabricated and delivered seismically qualified. The inspector expressed concern regarding discovery of the partial penetration welds and the implications of this discovery on the seismic qualification of the VY EDG welds. He discussed this concern with both NRC regional management and VY station management. Subsequently, VY initiated development of a Basis for Maintaining Operation (BMO) for the EDG weld issue, to be completed by September 17.

BMO 97-39, "Possible Less than Full Penetration Welds on Vendor Supplied Skid Mounted Piping for the Emergency Diesel Generators," was reviewed by the plant operations review committee (PORC) on September 17. The licensee determined the EDGs were operable based on:

1. Visual inspection of the welds that showed no obvious external defects.

2. The vendor's position that the welds were deemed acceptable based on many years of successful in-service operation of their equipment.

3. Successful operation of Fairbanks Morse diesels in harsh environments, including temperature, vibration, and shock.

4. Analyses that had been performed by another licensee, which indicated that less than full penetration welds (in their case, 66 percent) were acceptable.

5. VY EDGs had been evaluated as part of the seismic qualification upgrade (SQUG); the SQUG data base included diesels of similar vintage that had gone through seismic events of magnitudes in excess of VY's design basis and did not fail.

6. Preliminary calculations indicated that the EDG piping of concern had significant margin to ASME Code B31.1 limits, for both normal loading and seismic loading.

On September 22, VY started an LCO maintenance outage on the 'B' EDG. As a result of the weld issue, a section of lube oil system piping was removed for destructive examination. The piping is approximately 4-inch diameter and contains 6 welds. There are two material thicknesses, 0.250 and 0.120-inch, and three weld combinations, 0.250 to 0.250, 0.250 to 0.120, and 0.120 to 0.120. Weld penetration was determined by an off-site lab (Massachusetts Materials Research) to be 50% for the 0.250-to-0.250 weld, and 22% for the 0.120-to-0.120 weld.

During the inspection, a crack was found in the 0.250-to-0.250 weld, through wall, starting from the root. The crack was about 0.5-inch in length, or 4% of the circumference. The crack was on the same weld (first weld downstream of the LO pump discharge) and in the same location on the weld as had developed a leak at Millstone Unit 2. The VY engineering staff concluded that the crack would self-arrest at about 120° circumferential due to reaching the compressive side of the weld, and would result in a leak rather than a catastrophic failure. During this inspection period, VY had also conducted structural testing by applying tensile stress equivalent to the operating stress, and then applying a bending moment of 6 times the combined operating and seismic stress to the weld. The weld did not fail this structural test.

c. Conclusions

At the end of the inspection period, the licensee had completed formal EDG support piping stress analyses and had completed a metallurgical analysis which the licensee has concluded supports their initial operability determination. These items were under review by the NRC staff. Pending the results of further NRC staff review, the EDG support piping welds issue is being tracked as an inspector follow-up item **(IFI 97-08-01)**. The licensee's response to this issue, to date, has been consistent with the guidance of Generic Letter 91-18 for identification and resolution of a degraded or non-conforming condition.

E2 Motor-Operated Valve Program Review (TI 2515/109)

E2.1 Introduction

On June 28, 1989, the NRC issued Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," which requested licensees to establish a program to ensure that switch settings for safety-related motor-operated valves (MOV)s were selected, set, and maintained properly. Seven supplements to the GL have been issued to provide additional information and guidance on development of programs. NRC inspections at Vermont Yankee (VY) were conducted based on guidance contained in NRC Temporary Instruction (TI) 2515/109, "Inspection Requirements for Generic Letter 89-10."

On December 29, 1995, VY notified the NRC that the GL 89-10 program was complete. The NRC had previously conducted an initial programmatic (Part 1) inspection at VY in May 1991, as documented in Inspection Report (IR) 91-80. During October 1993, the NRC performed an implementation (Part 2) inspection, as documented in IR 93-16. A closure (Part 3) inspection for the purpose of verifying that VY completed its commitments to develop and implement a safety-related MOV program as described in GL 89-10 and its supplements was performed in May 1996, (IR 96-05). During that inspection, the NRC determined although the VY staff had generally implemented an acceptable GL 89-10 program, the following items were noted:

- Design basis evaluations of non-dynamically tested MOV's in accordance with Attachment 6 of "Engineering Guideline for Evaluation of Motor-Operated Valve Design Basis Capability" were not completed.

- The assumptions applied to grouped MOVs were not adequately supported by test data.

To address the above items, in letters dated April 18, and May 9, 1996, respectfully, VY agreed to use the Electric Power Research Institute (EPRI) thrust performance prediction program on six MOVs identified in GL 89-10 supplement 3 and two valves classified as "high risk" in the Individual Plant Examination (IPE) report. Additionally, the design basis evaluations of non-dynamically tested MOV's described in the MOV program manual would be completed by July 1, 1996. Finally, fifteen additional "high risk" valves would receive dynamic tests during the 1996 refuel outage.

The purpose of this fourth inspection was to examine the actions implemented at VY to address the closure issues identified during the Part 3 inspection and determine if those actions were sufficient to warrant "closure" of the NRC staff review of the GL 89-10 MOV program.

E2.2 Evaluation of High Risk MOV Dynamic Test Results

a. Inspection Scope

Fifteen valves received dynamic tests during the previous refuel outage. Of those valves, the inspectors selected the test results for the following MOVs for review:

V10-16A/B	Residual Heat Removal (RHR) Pump Discharge Mini Flow Returns to the Suppression Pool
V10-25A/B	RHR to Recirculation Loop Isolation Valves
V10-39A/B	RHR Containment Spray/Suppression Pool Cooling Supply Valves
V14-5A	Core Spray Pump Minimum Flow Valve
V70-19B	Service Water Supply Header Cross Connect Valve

The review consisted of examining data associated with: (1) valve factor, which correlates differential pressure to the stem-thrust requirement; (2) stem friction coefficient, which affects the conversion of actuator output torque to valve-stem thrust; and (3) rate of loading or load sensitive behavior, which reflects the change (usually a loss) in deliverable stem thrust under dynamic conditions as compared with the available thrust measured under static conditions. The inspectors also reviewed, "Vermont Yankee Engineering Guideline for Evaluation of MOV Design Basis Capability," Rev. 1, dated March 12, 1996, and calculations which evaluated differential pressure tests performed on the Residual Heat Removal (RHR) Service Water (SW) and Core Spray (CS) systems.

b. Observations and Findings

General

The "Vermont Yankee Engineering Guideline for Evaluation of MOV Design Basis Capability," outlined the process used to establish MOV switch settings, evaluate data and monitor valve performance. The document also contained the assumptions used to determine valve factor, load sensitive behavior, stem friction coefficient, and various capability margins. The engineering guideline also specified the statistical methods used to evaluate multiple test results.

When performing MOV testing (under static or dynamic conditions), valves were stroked three times in each direction. This allowed personnel to assess the valve's ability to perform in a consistent manner. Each performance parameter was determined or evaluated using a "student's t" statistical evaluation of the three test results using a 95% confidence level. The inspectors noted VY completed the evaluations required in Attachment 6 of the MOV program manual. Therefore, this closure item identified in NRC inspection report 50-271/96-05, was resolved.

Test Results

VY used the standard industry equations and a statistical evaluation of three dynamic tests (for each valve), to determine actuator capability margins, structural margins, valve factors, load sensitive behavior, and stem friction coefficients. MOV performance parameters (i.e. , valve factor, load sensitive behavior, and stem friction coefficient) were compared with previous dynamic test results to verify program assumptions were valid.

Apparent valve factors and load sensitive behavior values measured during dynamic testing of the selected MOVs were bounded by the current program assumptions (i.e., 0.60 for gate valve factors, 1.10 for globe valve factors, and 10% margin for load sensitive behavior). However, the test results for globe valves V10-34B and V13-27 had measured load sensitive behavior values of 17.9% and 13.8%, respectfully. Further, the test results were not fed back into the individual valve's component thrust calculation.

The inspectors noted this observation appeared to be restricted to a few valves. To ensure future MOV thrust calculations reflected the results of test data, VY committed to revise the existing calculations to reflect the results of test data for each dynamically tested valve. Program documents would also be revised as appropriate to reflect this expectation. The inspectors determined the corrective action was appropriate to resolve this observation.

Based on the load sensitive behavior performance noted for valves V10-34B and V13-27, the inspectors reviewed the dynamic test data for the remaining population of globe valves. This review included performing a "student's t" statistical analysis of all available in-plant globe valve load sensitive behavior data. Based on this review, the inspectors determined an 18% margin for load sensitive behavior should be applied to non-dynamically tested globe valves. The inspectors also performed a similar review of globe valve dynamic stem friction coefficient performance and determined that the assumed value of 0.15 was non-conservative as compared to a 0.16 value that resulted from analysis of the available in-plant globe valve test data.

Although the VY staff's assumptions for load sensitive behavior and stem friction coefficient did not bound the majority of the globe valve test data, the inspectors noted this finding did not affect valve operability since the non-dynamically tested globe valves had adequate design margin. At the conclusion of this inspection, VY committed to perform a review of the globe valve dynamic test data and provide an additional allowance to account for the effects of load sensitive behavior for non-tested globe valves.

c. Conclusions

Overall, the dynamic test results reaffirmed the design assumptions used to establish MOV switch settings. The exception was the load sensitive behavior assumption for globe valves, which did not appear to bound the majority of the test data. In some instances, component calculations were not updated to reflect the latest test data. Neither of these observations was significant, since the examined MOVs had adequate capability and the thrust calculations were generally up-to-date. VY committed to resolve these items by January 30, 1998, which was acceptable for program closure.

E2.3 Use of the Electric Power Research Institute Thrust Calculation Program

a. Inspection Scope

The inspectors reviewed calculations performed on valves in the Reactor Water Cleanup (RWCU), High Pressure Coolant Injection (HPCI), and the Reactor Core Isolation Cooling (RCIC) systems to assess how VY used the Electric Power Research Institute (EPRI) performance prediction methodology MOV thrust calculation program. Additionally, the inspector reviewed a summary analysis, which compared the thrust calculated by the EPRI program to the thrust produced by valves with their current switch settings.

b. Observations and Findings

The VY staff had properly used the EPRI calculational program. Specifically, default friction coefficients were used when necessary, the appropriate valve disc and guide material combinations were specified, and the system model used blowdown flow parameters to establish the design-basis requirements. However, one exception was noted, VY did not perform the calculations needed to estimate the unwedging loads for valves V13-21 and V23-19, which had open safety functions. VY indicated these calculations would be completed by December 1997.

The six Supplement 3 MOVs were evaluated for the closing safety function under blowdown flow. The initial EPRI calculation for these valves indicated that the thrust requirements were unpredictable. This result was caused by the software inputs that specified sharp guide edges for the valve disc. VY revised the input values to reflect a 0.04" chamfer for the guide edges, which resolved the software's unpredictable results. This change was based on valve internals inspections performed on all of the affected valves.

The results of the EPRI program were reconciled in an analysis, dated March 10, 1997, which compared the EPRI predicted thrust requirements to the current thrust requirements contained in the component calculations. The existing in-plant valve switch settings exceeded the EPRI predicted thrust requirements for all six Supplement 3 MOVs. However, the in-plant open thrust requirements were non-conservative for two non-Supplement 3 valves, which had open safety functions. The VY staff indicated both valves had adequate thrust capability to ensure proper operation considering the higher EPRI values. Therefore, the EPRI results did not affect valve operability.

VY is correctly using the EPRI program to validate the current switch setting on all applicable valves. The inspector considered this initiative to be a program strength.

c. Conclusions

VY properly used the EPRI program to develop predicted thrust values. The exception was the failure to complete and apply the unwedging hand calculations for two valves. This omission will be corrected by December 1997, which would be acceptable for program closure.

E2.4 Valve Grouping

a. Inspection Scope

The inspectors reviewed the grouping methodology used to analyze the performance characteristics of non-dynamically tested MOVs. The review consisted of an examination of dynamic test data and grouping criteria outlined in the MOV program manual.

b. Observations and Findings

VY divided their MOVs into six valve groups based upon manufacturer, type, and stem orientation. However, the inspectors determined that the grouping criteria were too broad to provide meaningful comparisons between valve types.

For example, one group contained Anchor Darling double disc gate valves which ranged in size from four to 28 inches. VY was not able to dynamically test any of the valves, so a valve factor of 0.50 was assumed based on analysis of eleven Anchor Darling valves tested at another nuclear station. However, the inspectors noted that the largest valves tested at the other station were six inches in diameter. It was not evident that this data would be applicable to all valves in this group population. The VY staff was also unsure if the data was obtained from valves oriented in the "preferred" direction (i.e., with the lower wedge downstream). Industry testing has shown that disc orientation in the "non-preferred" location can increase the thrust requirements to close the valve.

Based upon this observation, the VY staff committed to improve upon the current grouping methodology by analyzing the performance of the non-dynamically tested valves using the EPRI PPM program. If the thrust predicted by the EPRI program is greater than the current MOV setup, the licensee committed to revise the MOV switch settings. The licensee agreed to complete the validation process by January 30, 1998.

c. Conclusions

Although the current MOV grouping criteria were questionable, VY intends to address this observation by using the EPRI PPM program and adjusting MOV switch settings as appropriate by January 30, 1998. The inspector concluded this approach would be acceptable for program closure.

E8 Miscellaneous Engineering Issues (92700)

E8.1 (Open) IFI 96-11-01: Emergency Diesel Generator (EDG) Tornado Protection

a. Background and Inspection Scope (92903)

Licensee staff follow-up of an industry operating event report (NRC Information Notice 96-06, involving plant structures' tornado pressure relief), identified that the EDG enclosures did not contain the differential pressure relieving capability specified by the construction drawings. EDG operability was promptly assessed by the VY staff and the Basis for Maintaining Operation (BMO) process was initiated. As documented in inspection report 96-11, the inspector found the compensatory actions taken to have been appropriate, however, final resolution to this plant design issue was pending. The inspector conducted a follow-up inspection of this issue to evaluate the licensee's corrective actions and their progress in resolving this design concern.

b. Observations and Findings

The inspector determined that the current revision to BMO No. 96-08, "Effect of design basis tornado pressure load on the diesel/day tank room enclosures," (revision 4, dated 9/11/97) maintains the compensatory measures to block open the EDG enclosure access doors when tornado conditions are anticipated. These manual actions have remained in effect, even though the EDG enclosures were modified in April 1997 with automatic spring actuated differential pressure relieving dampers. The inspector determined that the compensatory measures remain in place to address a discrepancy found in the tornado loading accident analysis. Specifically, the discovery by the VY staff that the turbine building does not have a pressure relieving capability in the event of a high energy line break (HELB) (reference inspection report 97-02, section O1.4), potentially invalidates the analysis assumption that the turbine building pressure is essentially atmospheric at time zero in the tornado loading accident scenario response time-line. Consequently, the design basis tornado load (300 mph winds with an accompanying 3 psig pressure change in 5 seconds) impacting on the current EDG enclosure and turbine building would potentially result in the EDG-to-turbine building concrete block wall being subjected to a differential pressure in excess of its allowable design limit (1 psig).

The inspector determined that engineering design change request (EDCR) 97-419 is under development to address the turbine building HELB pressure relieving concern and is targeted for field installation by December 1997. Preliminary discussions with the responsible design engineering staff and plant management identified that EDCR 97-419 was not originally proposed as a vehicle to resolve the apparent discrepancy with the tornado accident analysis time-line assumption. However, the licensee acknowledged the inspector's observation that the two design issues were connected and, at the conclusion of the inspection period, VY was examining avenues to resolve this apparent design assumption conflict within the scope of EDCR 97-419.

c. Conclusions

The VY staff's pursuit of resolving the EDG enclosure tornado loading differential pressure vulnerability demonstrated a generally thorough examination of related turbine building HELB structural design attributes. **IFI 96-11-01** remains open, pending inspector review of the VY staff's final resolution of this EDG enclosure differential pressure concern.

E8.2 (Closed) LER 96-11 and NCV 97-08-06: Failure to perform Inservice Testing (IST) on valves that should have been included in the IST Program.

These licensee identified IST Program deficiencies involved the failure to include the high pressure coolant injection (HPCI), reactor core isolation cooling (RCIC), and core spray (CS) systems' alternate keep fill system (condensate transfer system) check valves (V23-20B, V13-20B, V14-22A/B, and V14-23A/B) in the IST Program for quarterly reverse flow cessation stroke testing. The identification of these testing oversights was part of an ongoing comprehensive IST Program review initiated in late 1995 (reference inspection reports 95-22 and 95-23 and associated LERs 95-17 and 96-01).

As stated in LER 96-11, dated May 16, 1996, the April 25 radiography testing (and subsequent testing) of the effected check valves identified proper valve seating to prevent reverse flow. The VY staff revised the IST Program to include these valves for future testing and continued their comprehensive IST program review with no additional discrepancies noted. The inspector determined that VY appropriately documented and reported this event. The inspector also verified that a dedicated IST Program coordinator was assigned, as stated in LER 96-11. The inspector assessed that corrective actions taken for prior violations in this area would not have reasonably prevented this violation. This licensee identified and corrected violation was treated as a non-cited violation **(NCV 97-08-06)**, consistent with Section VII.B.1 of the NRC Enforcement Policy. LER 96-11 is closed.

E8.3 (Closed) LER 96-14, Supplement 1: Tornado protection not provided for diesel generator rooms as specified in the Final Safety Analysis Report due to failure to implement plant construction/configuration change documents.

Supplement 1, dated January 29, 1997, documented the results of the licensee's root cause evaluation for this event and the associated corrective actions. As previously documented in inspection report 96-11 and in Section E8.1 of this report, this condition is being addressed via BMO No. 96-08, revision 4. As stated in Section E8.1, **IFI 96-11-01** remains open to track licensee final resolution and inspector review of this issue. LER 96-14, Supplement 1 is closed.

E8.4 (Closed) LER 96-21: Inadequate procedural controls of MOV limit switch settings results in a potential common cause failure mode with the capacity to affect multiple safety significant components.

LER 96-21, dated October 7, 1996, was reviewed in conjunction with inspection follow-up item **IFI 96-09-03**, which was closed in inspection report 97-05, section E8.2. As previously documented, this licensee identified and corrected violation was treated as a non-cited violation consistent with Section VII.B.1 of the NRC Enforcement Policy. The inspector concluded that LER 96-21 appropriately satisfied the NRC reporting requirements of 10 CFR 50.73. LER 96-21 is closed.

E8.5 (Open) URI 97-03-02: Cable separation does not satisfy UFSAR separation criteria. This unresolved item pertains to a number of licensee identified discrepancies between the as-built wiring at the plant and the cable separation criteria stated in the UFSAR associated with safety-related circuits. The following information updates the unresolved item.

The licensee reported in LER 96-028, dated November 18, 1996, another example of inadequate cable separation for the LPCI outboard isolation valve actuating circuits. This was identified and corrected during the October 1996 refueling outage. The licensee determined that the root cause for this event was an erroneous mis-labeling of the associated circuits during a 1976 design change. While the 1976 modification did not cause the circuits to violate the electrical separation criteria in the FSAR at that time, it resulted in the engineers not recognizing that the circuits were required to be separated since they were from different electrical divisions. Subsequent modifications resulted in the circuits being placed in a common, non-nuclear safety panduct, in violation of the cable separation criteria.

The inspector concluded that the licensee's immediate corrective actions were appropriate and brought the configuration of the affected circuits back into conformance with the FSAR criteria. Accordingly, LER 96-28 is closed, but the overall issue regarding cable separation remains unresolved pending further review of the licensee's evaluation and additional corrective actions, as necessary to prevent recurrence. A determination of future enforcement action for this unresolved item will include information from the licensee's efforts discussed in LER 96-28. **URI 97-03-02** remains open.

E8.6 (Closed) URI 93-16-01: Pressure Locking/Thermal Binding (PLTB) of Gate Valves

This item was opened to track the status of VY's corrective actions for gate valves determined to be susceptible to pressure locking. In a letter dated February 8, 1996, VY described the process used to evaluate valves for susceptibility to PLTB and its program to modify valves that may be susceptible to these phenomena. Currently only V13-20, the Reactor Core Isolation Cooling (RCIC) injection test valve, is susceptible to pressure locking. To address the pressure locking concern for this valve, a hole will be drilled in one side of the valve disc during the 1998 refuel outage. The actions taken by the licensee to address PLTB are currently under the review of the Office of Nuclear Reactor Regulation (NRR) who will evaluate the acceptability of the program in a safety evaluation report. Since NRR is now tracking the status of the PLTB program, maintaining a separate redundant unresolved item for the same purpose is no longer necessary. This item is closed.

E8.7 (Closed) VIO 96-05-03: Update and Control of MOV Program Manual

This violation was issued to document that the MOV program manual was not being updated in accordance with VY station administrative guidelines. As a result, the program manual contained outdated, conflicting, and contradictory information. To address this violation, the VY staff revised the program manual so that it described the current MOV practices. Further, the manual was placed under the document control procedure AP 6805 to ensure future program changes are routed and distributed in a timely manner. The inspector reviewed the program document and verified it described the approach used to establish MOV switch settings. The inspector concluded the licensee's actions were appropriate and this item is closed.

E8.8 (Closed) EA 95-070, VIO 01013: Failure to Correct a Condition Adverse to Quality

This violation documented weaknesses in the VY's corrective action processes including a failure to correctly analyze the susceptibility of core spray injection valves to pressure locking. As outlined in NRC inspection report 50-271/96-05, the inspector concluded VY's corrective actions appeared to be acceptable. However, two areas for improvement were noted and the violation was not closed. Specifically, the Basis for Maintaining Operability (BMO) guideline did not limit the time a degraded condition could remain in service before full equipment qualification was restored. Further it was not evident, the Nuclear Safety Audit Review Committee (NSARC) had performed a comprehensive assessment of the effectiveness of the corrective actions implemented in response to this violation. Based upon a review of the NSARC charter, the inspector concluded such a review was appropriate in exercising the full extent of the committee's responsibilities.

The inspector reviewed the BMO process and concluded adequate controls were established to limit the time a degraded or non-conforming condition could exist. The procedure now requires that a condition adverse to quality be dispositioned within specified time periods as defined in Administrative Procedure (AP) 0009, Event Reports. For example, category 1 event reports should be dispositioned within 45 days, category 2 within 90 days, and category 3 within 120 days. In addition, the BMO instruction states a periodic review (semi-annual) of all open items to verify that the conditions and assumptions remain valid shall be performed. The results of this review are then presented to the plant operations review committee (PORC).

The inspector noted there were 44 BMOs in place. VY intended to resolve each BMO before startup from the winter 1998 refuel outage. The VY staff had also performed an assessment to ensure the cumulative effect of outstanding BMOs would not have a deleterious effect on the operator's response to a transient. Based upon the corrective action, the inspectors concluded this issue was resolved.

To improve the oversight of plant operations, it appeared oversight groups increased the number of self assessments and independent audits performed on individual program areas. For example, a MOV program audit was completed in March 1997. The inspector noted such periodic reviews could provide valuable insight into the effectiveness of plant operations and should facilitate the evaluation of the licensee's corrective action process and resolve this weakness. This issue is closed.

IV. Plant Support

P3 EP Procedures and Documentation

a. Inspection Scope (82701)

Regional inspectors reviewed several changes the licensee made to the emergency plan and implementing procedures. The inspectors reviewed these changes in the NRC Region I office. They conducted this review to verify that the changes made to the Emergency Plan and implementing procedures were made in accordance with Part 50.54(q) of NRC regulations, (i.e., that they did not decrease the effectiveness of the Emergency Plan). The list of Emergency Plan sections and implementing procedures reviewed is contained in Attachment A of this report.

c. Conclusions

Based on the licensee's determinations that the changes did not decrease the overall effectiveness of the Emergency Plan, and that the Plan, as changed, continues to meet the standards of 10 CFR 50.47(b) and the requirements of Appendix E to Part 50, NRC approval of these changes is not required. The in-office review of these changes indicated them to have been made in accordance with 10 CFR 50.54(q).

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 (Closed) URI 97-06-02: Implementation of the Radioactive Liquid and Gaseous Effluent Control Programs

a. Inspection Scope (84750-01)

The inspection consisted of: (1) tour of the plant, including the control room; (2) review of liquid and gaseous effluent release permits; and (3) review of unplanned and unmonitored release pathways.

b. Observations and Findings

The inspector toured the control room and selected radioactive liquid and gas processing facilities and equipment, including effluent/process radiation monitoring systems (RMS) and air cleaning systems. All equipment was operable at the time of the tour. The inspector also noted that the licensee maintained air balances for reactor, turbine, and radwaste buildings to assure conformance to Final Safety Analysis Report (FSAR) specifications. The inspector noted that the licensee monitored a negative pressure only for the reactor building. (see Section R.2.3 of this inspection report for details.)

During the review of selected radioactive gaseous effluent discharge permits, the inspector determined that the discharge permits were complete and met the Technical Specification/Offsite Dose Calculation Manual (TS/ODCM) requirements for sampling and analyses at the frequencies and lower limits of detection established in the TS/ODCM. The inspector noted that there had been no radioactive liquid releases from the Vermont Yankee site for several years while pursuing effluent ALARA and plant water conservation.

The inspector also noted that there was one unplanned/unmonitored radioactive liquid or gas release since the previous inspection. The licensee found cracks in the radwaste building exhausting ventilation duct leading to the plant stack and the licensee made a 10 CFR 50.72 raport (ENS No. 32842) on August 29, 1997. The inspector reviewed the licensee's radiological and environmental assessment results. The inspector determined that the licensee's actions were acceptable and that there was no radiological impact to the public safety and the environment. Unresolved item **URI 97-06-02** is closed.

c. Conclusion

Based on the above reviews and observations, the inspector determined that the licensee maintained and implemented effective radioactive liquid and gaseous effluent control programs.

R2 Status of RP&C Facilities and Equipment

R2.1 Calibration of Effluent/Process/Area/Accident Radiation Monitoring Systems (RMS)

a. Inspection Scope (84750-01)

The inspector reviewed the most recent calibration results for the following effluent/process/area RMS and associated flow rate monitors to determine the implementation of the TS requirements and FSAR commitments:

- Steam Jet Air Ejector Offgas Monitors
- Main Stack Noble Gas Monitors (Normal and High Ranges)
- Main Stack Flow Rate Monitor
- Augmented Offgas (AOG) Building Noble Gas Monitors
- AOG Flow Rate Monitor
- Reactor Building Monitor
- Spent Fuel Pool Floor Monitor
- Liquid Radwaste Discharge Monitor
- Service Water Discharge Monitor

b. Observations and Findings

The I&C, Chemistry, and Radiation Protection departments had the responsibility to perform electronic and radiological calibrations for the above radiation monitors. All reviewed calibration results were within the licensee's acceptance criteria. The Chemistry Department performed trending analyses for the effluent RMS, which was considered a licensee strength.

During the review of the above RMS calibration documentation, the inspector independently calculated and compared several calibration results, including linearity tests and conversion factors. The inspector determined that the licensee's results were comparable to the independent calculations.

c. Conclusions

Based on the above reviews, the inspector determined that the licensee maintained and implemented a good calibration program and good trending analyses for effluent radiation monitoring systems.

R2.2 Air Cleaning Systems

a. Inspection Scope (84750-01)

The inspector reviewed the licensee's most recent surveillance test results (in-place HEPA and charcoal leak tests, air capacity tests, pressure drop tests, and laboratory tests for the iodine collection efficiencies) for the standby gas treatment system (SBGT) required by TS. In-place HEPA and charcoal surveillance tests for the Advanced Off-Gas (AOG) system and the radwaste building air cleaning system were also reviewed.

b. Observations and Findings

All surveillance results were either within the TS acceptance criteria or the administrative acceptance criteria.

Recently, the Office of Nuclear Reactor Regulation (NRR) identified that there was a potential conflict regarding the charcoal testing methodology for the iodine collection efficiency performed by the licensee/contractor laboratory. Normally, the licensee's TS specifies Regulatory Position C.6.a of RG 1.52, Revision 2, March 1978, as the requirement for the laboratory testing of the charcoal. RG 1.52 references ANSI N509-1976, "Nuclear Power Plant Air-Cleaning Units and Components." ANSI N509-1976 specifies that testing is to be performed in accordance with paragraph 4.5.3 of RDT M-161T, "Gas Phase Adsorbents for Trapping Radioactive Iodine and Iodine Components." The essential testing criteria are: (1) 70% or 95% relative humidity (RH); (2) 5-hour pre-equilibration time, with air at 25° C and plant specific RH; (3) 2-hour challenge, with gas at 80° C and plant-specific RH; and (4) 2-hour elution time, with air at 25° C and plant-specific RH. The latest acceptable methodology for the laboratory testing of the charcoal is

ASTM D 3803-1989, which requires licensees to maintain 30° C during all testing phases.

The inspector noted that the VY staff performed two separate surveillance tests for the SBGT: (1) ANSI 509-1980 and ASTM D-3803 Method C-1979 (130° C and 95% RH); and (2) ASTM D 3803-1989 (30° C and 95% RH). The licensee recognized that there was a potential problem for the iodine collection efficiency test methodology. The licensee, therefore, added the ASTM D 3803-1989 methodology in May 1995 and trended iodine collection efficiencies obtained from both methodologies. The inspector concluded that the licensee utilized an excellent surveillance test methodology for the SBGT system, and met all regulatory requirements.

c. Conclusions

Based on the above reviews, the inspector determined that the licensee maintained the plant air cleaning systems in accordance with established design specification. The licensee performed excellent iodine collection efficiency test methodologies for the SBGT system.

R2.3 Plant Air Balance

a. Inspection Scope (84570-01)

The inspection consisted of: (1) review of the main stack exhaust flow rate; (2) review of exhaust flow rate from various buildings; and (3) assessment of the plant air balance.

b. Observations and Findings

Procedure OP 2611, "Gaseous Radwaste" listed maximum exhausting fan capacities of various buildings (e.g., reactor, turbine, and radwaste buildings). The exhaust air from these buildings was released to the environment through the main stack. The maximum exhaust air flow rate from these building was 181,900 cfm while the main stack flow rate was about 150,000 cfm. The difference, of about 32,000 cfm, potentially demonstrated that station ventilation systems were not properly balanced. The original plant air balance data, measured in 1971 (150,000 cfm), was no longer valid since the turbine building exhaust was connected to the main stack in 1993. The licensee estimated that the main stack air flow exhaust would be increased, from 150,000 cfm to 200,000 cfm, due to addition of the turbine building ventilation (see inspection report Nos. 50-271/93-25 and 50-271/94-27 for details). Verification and corrections to exhaust fan capacities (actual and maximum) listed in procedure OP 2611, "Gaseous Radwaste," will be reviewed during a subsequent inspection **(IFI 97-08-02)**.

The licensee maintained a negative pressure in the reactor, turbine, and radwaste buildings. The licensee monitored differential pressure daily in the control room for the reactor building. However, the licensee maintained a negative pressure for the turbine and radwaste building through damper position indications since there were no installed delta-P gauges. The licensee planned to install delta-P gauges for turbine and radwaste buildings to assure the negative pressure was maintained. This action will also be reviewed by the inspector during a subsequent inspection **(IFI 97-08-02)**.

c. Conclusions

Based on the above reviews, the inspector made the following conclusions:

- the actual and maximum fan capacities listed in procedure OP 2611 should be verified to avoid a potential inaccurate projected dose calculation to the public;

- the licensee maintained the negative pressure for the reactor building verified delta-P daily using a installed gauge;

- the licensee maintained air balance for turbine and radwaste buildings through administrative means (e.g., damper position); and,

- the licensee planned to install delta-P gauges for the turbine and radwaste buildings.

R3 RP&C Procedures and Documentation

a. Inspection Scope (84570-01)

The inspection consists of a review of: (1) selected chemistry procedures to conduct the effluent control programs; (2) second half of the 1995 Semiannual Report and the 1996 Annual Radioactive Effluent Release Reports; (3) the ODCM; and (4) implementation of 40 CFR 190 requirements.

b. Observations and Findings

The inspector noted that reviewed effluent control procedures were detailed, easy to follow, and ODCM requirements were incorporated into the appropriate procedures. The licensee had good procedures to satisfy the TS/ODCM requirements for routine and emergency operations.

The inspector reviewed the 1995 Semiannual and the 1996 Annual Radioactive Effluent Release Reports. These reports provided data indicating total released radioactivity for liquid and gaseous effluents. The assessment of the projected maximum individual doses resulting from routine radioactive airborne and liquid effluents were listed as required. Projected doses to the public were well below the TS limits. The inspector determined that there were no anomalous measurements, omissions, or adverse trends in the reports.

The ODCM provided descriptions of the sampling and analysis programs, which were established for quantifying radioactive liquid and gaseous effluent concentrations, and for calculating projected doses to the public. All necessary parameters, such as effluent radiation monitor setpoint calculation methodologies, and site-specific dilution factors, were listed in the ODCM. The licensee adopted other necessary parameters (dose factors) from Regulatory Guide 1.109.

Section 3/4.8.M of the TS requires that the licensee shall comply with the 40 CFR 190 requirements, 25 mrem/year to the total body to a member of the public with occupancy rate at the monitoring location. The inspector reviewed the 1996 Annual Radiological Environmental Surveillance Report and Effluent Report including projected dose calculation results to the public. The licensee has 14 thermoluminescent dosimeters (TLDs) around the site boundary and two control TLDs stations (about 15 km from the plant) to comply with 40 CFR 190 requirements. The mean measurement value at the site boundary (including background) and control stations were 69.14 and 56.1 mrem/year, respectively, during 1996. The difference value, which is about 13 mrem/year, would be contributed from the plant operation. The licensee reported the maximum total body dose from facility direct radiation was about 14 mrem during 1996 at the west site boundary. However, there were no residents present at that location. Total body dose due to radioactive liquid and gaseous effluent releases was 0.05 mrem during 1996. The total dose would be 13.05 mrem during 1996 and the licensee met the TS requirements.

c. Conclusions

Based on the above reviews, the inspector made the following conclusions:

(1) effluent control procedures were sufficiently detailed to facilitate performance of all necessary steps for routine and emergency operations;

(2) the licensee effectively implemented the TS/ODCM requirements for reporting effluent releases and projected doses to the public; and,

(3) the licensee's ODCM contained sufficient specification, information, and instruction to acceptably implement and maintain the radioactive liquid and gaseous effluent control programs.

R6 RP&C Organization and Administration

The inspector reviewed the organization and administration of the radioactive liquid and gaseous effluent control programs and discussed with the licensee changes made since the last inspection. The inspector determined that there were no changes to the radioactive effluent control programs. The Chemistry Department has primary responsibility for conducting the radioactive liquid and gaseous effluent control programs. The System Engineering, Operations, Radiation Protection, and Instrumentation and Controls (I&C) Departments also have responsibilities to support effluent control programs, such as air cleaning systems, radwaste discharges, and radiation monitoring system calibrations (radiological and electronic calibrations).

R7 Quality Assurance (QA) in RP&C Activities

a. Inspection Scope (84750-01)

The inspection consisted of a review of: (1) the 1996 and 1997 QA audit reports; and (2) implementation of the measurement laboratory quality control program for radioactive liquid and gaseous effluent samples.

b. Observations and Findings

The inspector reviewed the 1996 and 1997 QA Audit Reports (Report Nos. VY-96-02 and VY-97-02). These audits were conducted by the QA Department staff and covered the radioactive liquid and gaseous effluent control programs, including the implementation of the ODCM. The inspector noted that the audits were conducted by members of QA Department with assistance from other technical personnel. The 1996 audit team identified one finding. The 1997 audit team identified no findings. The inspector determined that the 1996 finding was not safety significant, but was intended for the enhancement of the effluent control programs. Prompt corrective action was performed by the Chemistry Department staff.

The inspector reviewed the implementation of QC for the chemistry laboratory, including control charts, inter-laboratory and intra-laboratory comparisons. The inspector considered the chemistry laboratory QC program to be very good.

c. Conclusion

Based on the above review and interviews, the inspector determined that the technical depths of the audits was good and met TS requirements. The chemistry laboratory QC program was very good.

R8 Miscellaneous Issues

R8.1 Training

The inspector reviewed the training courses for the licensed operators, in the areas of radioactive liquid and gaseous effluent controls and discussed this program with a training instructor. Required training courses for operators appeared to be appropriate, and included subjects such as: solid and liquid radwaste processes; ventilation; ODCM; HVAC; AOG; area/process/effluent RMS; and service water. To complete these courses required about 60 hours in class and the use of simulator. The licensee also had the "Response Training" and an annual re-qualification training. The response training involved specific effluent events, such as Event Reports or LERs.

The inspector discussed with the plant staff the involvement of the Chemistry staff in response training. Currently, there is no Chemistry staff involvement for the response training and the annual re-qualification training. The licensee stated that they would evaluate Chemistry staff involvement in this training with respect to the effluent ALARA program.

R8.2 (Closed) URI 96-03-05, LER 96-03 Sup. 1, and NCV 97-08-07: Removal of Reactor Vessel Shield Blocks at Power

a. Inspection Scope (92904, 92700)

This issue was previously examined in inspection report 96-03, section 4.1, and inspection report 96-09, section R8.2 and remained open pending completion of the licensee's root cause evaluation. LER No. 96-03, Supplement 1, "Removed reactor shield blocks during power operations to facilitate outage scheduling due to personnel error," dated June 12, 1997, documented the VY staff's formal root cause evaluation results and associated corrective actions. The inspector conducted a review of LER 96-03, Supplement 1, and verified the implementation of the stated corrective actions.

b. Observations and Findings

The licensee's formal root cause of this event was personnel error, in that there was a lack of awareness by plant personnel in 1990 and 1992 of the consequences of removing all three sets of reactor cavity shield blocks while at power. A contributing cause identified by the VY staff was the lack of formal procedural guidance governing the removal of shield blocks. The inspector confirmed the adequacy of the licensee's corrective actions which included a revision to the refueling preparation procedure, Operating Procedure (OP)-1200, "Preparation of the Reactor Vessel for Refueling," revision 18, dated 9/5/96) section 1.0, "Drywell Shield Block and Drywell Head Removal," which added the requirement that "the first layer of shield blocks can be removed at any power level prior to shutdown, the second and third layers of shield blocks cannot be removed until the reactor vessel is <212 degrees F and vented." In addition, the licensee revised Plant Operations Review Committee (PORC) member training, engineering support staff continuing training, and the Safety Evaluation Training lesson plans to reflect the lessons learned from this event.

The inspector considered this refueling preparation event to have been reflective of past poor VY staff performance. This non-repetitive, licensee identified and corrected violation was treated as a non-cited violation **(NCV 97-08-07)**, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

Licensee actions to identify and implement corrective actions to prevent drywell shield blocks removal during power operations were appropriate. This licensee identified event involving the violation of regulatory requirements was not cited.

LER 96-03 and 96-03 Supplement 1 were closed and unresolved item **URI 96-03-05** was closed.

V. Management Meetings

X1 Exit Meeting Summary

The inspector presented the inspection results of the radiological environmental monitoring program to members of the licensee management at the conclusion of the inspection on September 26, 1997. The results of the MOV review were presented to station management at the conclusion of the on site inspection on October 17, 1997. The licensee acknowledged the findings presented.

The resident inspectors met with licensee representatives periodically throughout the inspection and following the conclusion of the inspection on November 20, 1997. At that time, the purpose and scope of the inspection were reviewed, and the preliminary findings were presented. The licensee acknowledged the preliminary inspection findings.

X2 Review of Updated Final Safety Analysis Report (UFSAR)

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed practices and procedures and/or parameters. However, the inspectors observed that the FSAR wording was questionable with respect to the observed plant practices, procedures, and parameters involving building air balance and flow (See Section R.2.3 of this inspection report). The inspectors reviewed Sections 4.4, and 4.8 of the VY UFSAR to assess if VY had incorporated correct UFSAR information into plant MOV procedures regarding reactor coolant and reactor water cleanup systems (RWCU), respectively. This information was found to be correct and up-to-date.

INSPECTION PROCEDURES USED

61726	Surveillance Observations
71707	Plant Operations
92901	Follow Up - Plant Operations
92903	Follow Up - Engineering
84750-01	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
82701	Operational Status of Emergency Preparedness Program
92700	LER review
62707	Maintenance Observations
92903	Engineering Follow-up
92904	Plant Support Follow-up
37551	Onsite Engineering Review
TI 2515/109	Inspection requirements for Generic Letter 89-10, "Safety Related Motor-Operated Valve Testing and Surveillance."

ITEMS OPENED, CLOSED, AND DISCUSSED

OPEN

IFI 97-08-01 Inspector follow-up of the licensee's resolution of the EDG piping welds issue.

IFI 97-08-02 Verification of exhausting actual and maximum fan capacities listed in Procedure OP 2611, "Gaseous Radwaste."

CLOSED

LER 96-03, Sup. 1	
LER 96-11	
LER 96-14, Sup. 1	
LER 96-21	
LER 96-23	
LER 97-11	
LER 97-12	
LER 97-14	
LER 97-17	
URI 96-03-05	Removal of reactor vessel shield blocks at power.
URI 97-06-02	Cracks in radwaste building vent ducting.
LER 96-29	
LER 96-24	
IFI 96-09-01	Appendix J testing deficiencies
LER 96-27	
URI 93-16-01	Pressure locking and thermal binding
VIO 96-05-03	Failure to update and control of Program Manual
EA95-070	VIO 01013: Failure to correct a condition adverse to quality
NCV 97-08-03	LER 96-23
NCV 97-08-04	LER 96-29
NCV 97-08-05	LER 96-27
NCV 97-08-06	LER 96-11
NCV 97-08-07	URI 96-03-05

DISCUSSED

LER 96-03	
IFI 96-11-01	EDG tornado protection
VIO 97-06-03	Ineffective corrective action, containment inerting event.
IFI 97-04-04	RHR service water flow instrument accuracy
IFI 97-06-01	Licensee's LSFT review follow-up
URI 97-03-02	Cable separation issues

PARTIAL LIST OF PERSONS CONTACTED

G. Maret, Plant Manager
F. Helin, Tech. Services Superintendent
M. Balduzzi, Superintendent of Operations
E. Lindamood, Director of Engineering
K. Bronson, Operations Manager
M. Watson, Maintenance Superintendent
G. Morgan, Security Manager
J. Chamberlin, System Engineer, Instrument and Controls
M. Desiletes, Radiation Protection Manager
R. Gerdes, Chemistry Manager
F. Helin, Technical Services Superintendent
S. Jefferson, Scheduling Manager, Operations
S. McAvoy, Chemistry Supervisor
D. Voland, Radiological Environmental Supervisor
C. Hansen, MOV Engineer
J. Lynch, Fluids Design Engineering
C. Nichols, Manager, E&C

LIST OF ACRONYMS USED

ALARA	As Low As is Reasonably Achievable
ARMS	Area Radiation Monitoring System
BMO	Basis for Maintaining Operation
CFR	Code of Federal Regulation
CR	control room
CS	core spray
EDG	emergency diesel generator
ER	Event Report
FSAR	Final Safety Analysis Report
GL	Generic Letter
HEPA	High Efficiency Particulate
HPCI	high pressure coolant injection
HVAC	Heating, Ventilation, and Air Conditioning
IFI	Inspector follow item
IN	Information Notice
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LPCI	low pressure coolant injection
MCC	motor control center
NRC	Nuclear Regulatory Commission
NNS	Non-nuclear safety
ODCM	Offsite Dose Calculation Manual
PORC	Plant Operations Review Committee
QA	Quality Assurance
QC	Quality Control
RHR	residual heat removal
RMS	Radiation Monitoring System
RP&C	Radiation Protection
SFP	Spent Fuel Pool
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
URI	unresolved item
VY	Vermont Yankee

ATTACHMENT A

List of Emergency Plan and Implementing Procedures Reviewed

DOCUMENT	TITLE	REVISION NO.
Emergency Plan Section 6.0	Emergency Facilities and Equipment	20
Emergency Plan Section 8.0	Organization	20
Emergency Plan Section 10.0	Radiological Assessment and Protective Measures	20
Emergency Plan Section 12.0	Maintaining Emergency Preparedness	19
Emergency Plan Appendix E	Letters of Agreement	22
OP 3504	Emergency Communication	DI 97-133
OP 3509	Environmental Sample Collection During an Emergency	15
OP 3535	Post Accident Sampling and Analysis of Primary Containment	2