January 6, 1997

EA No. 96-510

Mr. Donald Reid
Vice President, Operations
Vermont Yankee Nuclear Power Corporation
RD 5, Box 169
Ferry Road
Brattleboro, Vermont 05301

SUBJECT: NRC INTEGRATED INSPECTION REPORT 50-271/96-10

Dear Mr. Reid:

On December 7, 1996, the NRC completed an inspection at your Vermont Yankee (VY) reactor facility. The enclosed report presents the results of that inspection.

During the 7-week period, the VY staff's conduct of activities at the facility reflected good safety-conscious operations, sound engineering and maintenance practices, and careful radiological work controls. Unit restart following the Fall 1996 refueling outage was appropriately paced and well executed by the entire VY organization as a whole.

Your efforts for identifying and resolving 10 CFR Part 50, Appendix R/fire protection issues and enhancing staff understanding have provided good assurance and enhanced system reliability in support of safe plant shutdown in the event of a design bases fire at VY.

No reply to this report is necessary and your cooperation with us is appreciated.

Sincerely,

Original Signed By:

Richard J. Conte, Chief
Reactor Projects Branch No. 5
Division of Reactor Projects

Enclosure: NRC Inspection Report 50-271/96-10

Docket No. 50-271

Y/3

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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.	50-271
Licensee No.	DPR-28
Report No.	96-10
Licensee:	Vermont Yankee Nuclear Power Corporation
Facility:	Vermont Yankee Nuclear Power Station
Location:	Vernon, Vermont
Dates:	10/20 - 12/07/96
Inspectors:	William A. Cook, Senior Resident Inspector Edward C. Knutson, Resident Inspector Leanne M. Harrison, DRS Ram S. Bhatia, DRS
Accompanied by:	Leon E. Whitney, Plant Systems Branch, NRR
Approved by:	Richard J. Conte, Chief, Projects Branch No. 5 Division of Reactor Projects

EXECUTIVE SUMMARY

Vermont Yankee Nuclear Power Station
NRC Inspection Report 50-271/96-10

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection; in addition, it includes the results of announced inspections by regional engineering specialists and a headquarters fire protection specialist.

Plant Activities

The station completed refueling outage No. 19 on November 1 upon synchronizing of the generator to the grid. However, the main generator was taken off line after approximately one hour due to high vibration from the number 10 bearing. Corrective maintenance was performed on the bearing and the main generator was paralleled to the grid the following day. On November 3, operators manually tripped the turbine at 25 percent reactor power in response to increasing main condenser backpressure. The cause was found to be a failed level control valve for the atmospheric drain tank. The main generator was returned to the grid later the same day. The plant achieved full power on November 5, and operated there for the remainder of the inspection period.

Operations

Overall, plant staff performance during the unit restart sequence was good. Command and control of unit startup activities by the onshift control room operators was good. Communications by the shift crews was observed to be clear and precise. The inspectors witnessed various pre-evolutionary briefings held in the control room and noted appropriate sensitivity to procedural compliance, attention to detail, and to the maintenance of a questioning attitude for the planned activity and the resultant changing plant conditions.

Maintenance

The VY staff took appropriate action to identify the root cause of the "A" EDG output breaker failure and to implement prompt and comprehensive corrective actions. The safety consequences were minimized as a result of the "B" EDG operability and availability. The resultant TS limiting condition for operation non-compliance was not cited because the mechanical failure was not reasonably preventable or within the control of the VY quality assurance processes. The retraction of the September 24 10 CFR 50.72 report to the NRC was inconsistent with 10 CFR 50.72 guidance. Nonetheless, the breaker problems were reported and the 10 CFR 50.73 reports were appropriate and well written.

While attempting to place the "D" residual heat removal (RHR) pump in a shutdown cooling configuration, the pump start interlock was not satisfied and the pump failed to start. The cause of the failure was determined to be incorrect limit switch settings on the "D" RHR pump suction valve, RHR V10-15D. As a result of this and other maintenance-related MOV problems that occurred during the 1996 outage, the licensee has initiated a self-assessment of MOV maintenance activities.

Engineering

Licensee investigation in response to a 10 CFR 21 notification identified and confirmed a lack of full seismic qualification of two EDG protective relays. The VY staff's evaluation of this condition, which was determined to not affect EDG operability, was prompt and thorough.

The development and implementation of effective compensatory measures, along with the support provided by administrative controls and installed defense-in-depth design, provided good assurance that safe shutdown of the plant would be accomplished in the event of any postulated fire.

VY had addressed the Appendix R hot short concerns associated with the "A" EDG and other Appendix R systems correctly and had enhanced the overall system ability to shutdown the plant appropriately.

Rigorous efforts had been taken and proper corrective actions were planned or implemented to address previous fire protection ownership issues. VY staff understanding of fire protection was extensive and noteworthy.

The HPCI suction line, by design, does not provide a pathway for post-LOCA primary containment airborne containments to communicate to the atmosphere via the condensate storage tank vent. The VY staff analysis of these two HPCI system issues was thorough and well documented.

Plant Support

Rigorous efforts had been taken and corrective actions had been planned or implemented to correct previous fire protection ownership issues. The inspectors determined that these actions effectively improved VY staff understanding of NRC requirements, design bases information, and program commitments.

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DETAILS

Summary of Plant Status

At the beginning of the inspection period, Vermont Yankee (VY) was shutdown, with the 1996 refueling outage in progress. The post-refueling operating pressure test of the reactor coolant system was conducted on October 22 and the drywell was closed out on October 24. On October 30, the mode switch was placed in the STARTUP position and criticality was achieved at 10:10 p.m. Following completion of high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) turbine overspeed testing, the mode switch was placed in the RUN position at 10:30 p.m., October 31. The main generator was synchronized to the grid at 3:11 a.m., November 1, but was taken off line approximately one hour later due to high vibration from the number 10 bearing. This bearing was replaced while the reactor was maintained critical, and the main generator was again synchronized to the grid on November 2 at 5:00 a.m. After approximately four hours, the main generator was again taken off line to perform main turbine overspeed trip testing. Upon completion of testing, the main generator was placed on line at 10:35 a.m.

The following day, with reactor power at approximately 30 percent, operators noted increasing main condenser backpressure. A power reduction was commenced, but backpressure continued to increase to the point that operators manually tripped the main turbine. The cause of the increasing main condenser backpressure was a failed controller for one of the atmospheric drain tank level control valves. When the valve failed open, the tank drained to the main condenser; since the tank is vented to atmosphere, loss of the water seal caused condenser pressure to increase. The level control function for this tank was restored and the main generator was returned to the grid at 8:28 p.m., November 3. The plant achieved full power at 5:45 a.m., November 5, and, with the exception of short duration power reductions for rod pattern adjustments and routine surveillances, operated for the remainder of the inspection period at full power.

An NRC Headquarters lead team inspection was conducted on site November 6-15, 1996 to review the effectiveness of licensee controls for identifying, resolving, and preventing issues that degrade the quality of plant operations or safety. The results of this inspection will be docketed via a separate inspection report.

Prior to restart of the unit, region based and headquarters fire protection specialists were on site to verify the adequacy of interim compensatory measures established while the NRC staff reviews 10 CFR 50 Appendix R exemption requests. A subsequent inspection of the adequacy and implementation of selected fire protection program corrective actions was conducted.

On December 3, 1996, Richard Cooper, Director, Division of Reactor Projects, Region I and James Wiggins, Director, Division of Reactor Safety, Region I, were on site to conduct a plant tour and to interview a cross-section of the plant staff prior to convening the end of SALP cycle assessment board (the end of SALP period is January 18, 1997 and the SALP board is scheduled for January 30, 1997).

I. Operations

O1 Conduct of Operations[1]

O1.1 Operations Performance - Unit Restart

a. Inspection Scope (71707)

Using the guidance of Inspection Procedure 71707, the inspectors observed the various reactor and power plant restart activities following the Fall 1996 refuel outage as discussed above. The inspectors verified VY staff compliance with the applicable unit startup, operating, and testing procedures and observed the staff's resolution of the emergent equipment problems.

b. Observations, Findings, and Conclusions

The inspectors observed good command and control of unit startup activities by the onshift control room operators. Communications by the shift crews was observed to be clear and precise, with good use of the three-point (communicate, repeat back, and acknowledgement) communications. Based upon the observation of the turbine roll evolution and the high turbine bearing vibrations encountered, the inspector concluded that the communications and coordination between the operations and support staffs was equally good. The inspectors witnessed various pre-evolutionary briefings held in the control room and noted appropriate sensitivity to procedural compliance, attention to detail, and to the maintenance of a questioning attitude for the planned activity and the resultant changing plant conditions. Overall, plant staff performance during the unit restart sequence was good.

O8 Miscellaneous Operations Issues

O8.1 Licensee Event Report Review

a. Inspection Scope (92700)

Using the guidance of Inspection Procedure 92700, the inspectors reviewed the Licensee Event Reports (LERs) discussed below to verify the VY staff had implemented the corrective actions, as stated in the LERs, and to determine whether their response was appropriate and met regulatory requirements.

b. Observations, Findings, and Conclusions

- LER No. 96-022, EDG inoperable beyond its TS allowed limiting condition for operation action statement outage time, dated October 15, 1996, and Supplement - 01 to LER No. 96-022, dated November 18, 1996.

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[1] Topical headings such as O1, O8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

This event and the licensee's corrective actions are discussed in section M8.1 of this report. The inspector's assessment of the quality and timeliness of these reports was good. The licensee's discussion of the sequence of events, safety analysis, and root causes, was thorough, and the corrective actions appropriate.

- LER No. 96-010, Failure to previously identify dependency between the residual heat removal (RHR) minimum flow valve and the cross powered RHR pumps, dated May 9, 1996, and Supplement -01 to LER No. 96-010, dated September 13, 1996.

  LER No. 96-010 was previously examined as documented in inspection report 96-07. Supplement -01 was reviewed during this inspection period and found to have appropriately addressed the inspector's previous concerns with overall quality and completeness of the May 9, 1996 submittal. The root cause analysis was found to be thorough and self-critical, and the safety analysis of the as-found condition was determined to be significantly more thorough and complete. The corrective actions will be examined separately via follow-up to the cited violation (No. 96-210-01013, reference Notice of Violation and Proposed Imposition of Civil Penalty - $50,000, dated August 23, 1996).

- LER No. 96-01, Supplement -01, TS 4.6.E not met due to components not included in the Inservice Test Program scope, dated July 22, 1996.

  The original LER 96-01, dated March 1, 1996, was reviewed in inspection report 96-03 (Section 3.3.1) and dispositioned as a non-cited violation. Supplement -01 documents a more comprehensive summary of the Inservice Testing Program deficiencies identified by the licensee's detailed program re-assessment. Detailed followup of the corrective actions for these additional items and those IST program deficiencies identified during inspection reports 95-22 and 95-23 are planned for a subsequent inspection period.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Surveillance Observations

a. Inspection Scope (61726)

The inspector observed portions of surveillance tests using inspection procedure 61726 to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to limiting conditions for operation (LCOs), and correct post-test system restoration. The inspector observed portions of the following surveillance tests:

- OP-4126, Diesel Generators Surveillance, section C.1, Diesel Generator Readiness Demonstration Monthly, observed November 19.

- Reactor core isolation cooling system motor operated valve differential pressure testing, observed December 4.

b. Observations and Conclusions

The inspector identified no problems with the performance of the above system surveillance testing and verified proper adherence to the test procedures by the VY staff.

M1.2 (Open) IFI 96-10-01: Performance of On-line Electrical Bus Maintenance

On November 25, 1996 while operating at 100 percent power, the VY staff de-energized 480V electrical bus No. 6 for planned maintenance (reference Work Order No. 94-05726). The planned preventive maintenance was to be conducted per Operating Procedure (OP)-5229, Inspection and Testing of the GE 480 VAC Switchgear, Revision 2. Upon de-energization of Bus 6, the operations shift crew observed that the condensate demineralizers' inlet isolation valves closed and the condensate demineralizer bypass valve went open. This condensate system response was not anticipated, but subsequently determined to be as designed.

The inspector determined that prior to this operating cycle, on-line electrical bus preventive maintenance was not conducted. The inspector also learned from discussions with responsible planning and maintenance personnel that the condensate control panel de-energization was anticipated, but the failure mode (upon loss of electrical power) of the condensate demineralizer valves was thought to be "fail-as-is". Based upon the unanticipated plant equipment response, the operations staff was assigned a root cause evaluation per the Event Report (ER) system (reference ER No. 96-01131). At the conclusion of the inspection period, the licensee had not completed their evaluation of this event. Inspector follow-up of this issue is planned in a subsequent inspection period (IFI 96-10-01).

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) IFI 96-09-02: "A" EDG Output Breaker Closure Mechanism Failure

a. Background

As previously documented in inspection report 96-09, the VY staff found that the "A" emergency diesel generator (EDG) output breaker (type GE AM4.16Kv-250-8HB, Magneblast) was inoperable on September 13 while implementing a protective tagout to perform preventive maintenance. The breaker closing springs were found discharged when the breaker was racked down per the tagout. Initial investigation by the performance engineering staff identified two of the four charging motor mounting screws laying in the bottom of the breaker cubicle and a third mounting screw was loose. This condition did not explain the failure of the closing springs to recharge, but all similar 4kv breakers were promptly inspected to verify tightness of charging motor mounting screws (reference Morning Report 1-96-0085, dated September 17, 1996). A subsequent detailed inspection on September 17 by the electrical maintenance staff (Work Order 96-09504) identified that the charging motor had failed (motor windings fused) and that the charging motor ratchet pawl hinge pin had disengaged (hinge pin holds the latching pawls which engage the ratchet wheel of the charging motor). This condition indicated that the EDG output breaker closing spring did not recharge when the breaker was last cycled open and that the charging motor likely ran to failure.

b. Inspection Scope (62707, 92902)

The inspector reviewed the sequence of events and root cause evaluation developed by the VY staff. Corrective actions as documented in LERs No. 96-022, dated October 15, 1996, and No. 96-022, Supplement 01, dated November 18, 1996, were reviewed and verified.

c. Observations and Findings

As documented in inspection report 96-09, Section O1.2, the licensee took appropriate corrective actions for this breaker concern prior to unit restart on October 30. These actions included: replacement of the "A" EDG output breaker with a spare; closing springs on all 4kv breakers were verified to be charged; 100 percent inspection of all 4kv breakers to verify condition of the charging motor ratchet pawl hinge pin; awareness training was conducted for electrical maintenance and operations staff; and interim action to verify closing spring status after any 4kv safety class breaker is cycled was initiated. The inspector noted that the "B" EDG remained operable and available the entire time period the "A" EDG was inoperable and was subsequently tested and verified to have been operable via monthly surveillance testing and cyclic ECCS integrated testing.

As captured in LER No. 96-22 and its supplement, the VY staff was able to conclude that, due to the nature of the "A" EDG output breaker failure, the breaker closing springs were discharged since August 20, 1996 (breaker opened following monthly surveillance test). The only available indication that the closing springs had failed to charge was the mechanical flag indicator located behind the breaker cubicle door. However, there were no procedural requirements or routine watchstanding or maintenance practices in affect at the time to cause this flag to be verified following breaker cycling.

Based upon followup with the VY and NRC Headquarters technical staffs, the inspector determined that roughly half of the nuclear utilities using these type 4kv breakers have visual keys (mechanical flags, windows, or indicating lights) on the breaker cubicle doors to indicate the status of the breaker closing springs. A significant amount of industry operating experience has been communicated about these types of 4kv breakers, however, no specific breaker failures attributable to the cotter pin failure on the ratchet pawl hinge pin have been previously identified. A GE Service Advisory Letter (SAL), dated July 7, 1995, did highlight a 1979 design change (one of six developed between 1965 and 1990) involving the changing of the cotter pin ratchet pawl hinge pin with a bolted hinge pin. As stated in the GE SAL, this design change was recommended "to facilitate removal for maintenance" vice a fix of any known failure mechanism.

Due to the nature of the "A" EDG output breaker failure, the breaker closing springs did not recharge following the last successful surveillance test and output breaker cycling on August 20, 1996 (last opened at 4:05 p.m.). The discovery of this breaker failure by the licensee staff on September 13, 1996 resulted in the determination that the "A" EDG had been inoperable since August 20, or for approximately 25 days. Technical Specification 3.10.B.1 and 3.5.H.1 state that "with one EDG inoperable continued reactor operation is permissible only during the succeeding seven days, provided all of the low pressure core cooling and containment cooling subsystems connecting to the operable diesel generator shall be operable." Since the unit was operating at power during the period of August 20 through to September 6, 1996, and the "A" EDG was inoperable during this time period, the unit was in operation contrary to TS 3.5.H.1 from August 27, 1996 to September 6, 1996 (8:19 p.m.), when the reactor mode switch was taken out of STARTUP and placed in REFUEL. In light of the above, the NRC staff determined that the TS limiting condition for operation was violated, but resulted from circumstances not within reasonable licensee control, in that, the failure of the cotter pin could not have been avoided or detected by the licensee's quality assurance program and/or related control measures. Accordingly, this violation of TS 3.5.H.1 is not being cited, consistent with section VI.A. of the NRC Enforcement Policy.

Inspector review of the VY staff's reporting of this 4kv breaker problem identified some minor weaknesses and inconsistencies. Upon discovery of the "A" EDG output breaker problem, the VY staff reported the condition per 10 CFR 50.72(b)(2)(iii)A, "non-emergency, 4-hour report of an event or condition that alone could have prevented the fulfillment of the safety function of a system needed to shutdown the reactor and maintain it in a safe shutdown condition" (reference Event No. 31004, dated September 14, 1996). On September 24, 1996, the VY staff retracted the September 14 notification based upon further evaluation that concluded that the EDG output breaker "failure mode was unique, and does not affect other breakers in the plant." Later, on October 22, 1996, the VY staff reported per 10 CFR 50.72(b)(2)(iii)(B) and (D), "non-emergency, 4-hour report of an event or condition that alone could have prevented the fulfillment of the safety function of a system needed to (B) remove residual heat, and (D) mitigate the consequences of an accident" (reference Event No. 31192, dated October 22, 1996).

A historical examination of the sequence of events involving this breaker problem (as documented in the licensee's LER, event report, and root cause analysis, identified that the initial NRC notification (Event No. 31004) was appropriate and should not have been retracted. The basis for this finding is that on September 14 the licensee was cognitive of the fact that the EDG had been inoperable for 25 days and that the unit had been operated outside of its licensing basis from August 27 to September 6. This alone was reportable per 10 CFR 50.73(a)(2)(i)(B). Also, on September 14, the inspector viewed the 10 CFR 50.72 notification as appropriate, in that, the potential generic implication of the breaker failure (suspected at that time to be related to the charging motor failure) were not known and the VY staff conservatively made the notification. On or about September 17, a detailed investigation by the VY maintenance staff of the failed breaker identified that the ratchet pawl hinge pin cotter pin failure caused the breaker closing spring charging mechanism to fail to function. Although the inspector acknowledges that the breaker failure mechanism known to the licensee on September 24 (date of retraction of Event No. 31004) was not the same as suspected by the licensee on September 14, the potential generic implications were still prevalent due to the newly determined failure mechanism (all 4kv breakers had not been inspected yet) and, therefore, the notification should not have been retracted. Notwithstanding, the licensee did subsequently recognize the appropriate reporting requirements on October 22 and Event No. 31192 was initiated. Further, the docketed LERs (No. 96-22 and its supplement) were found to be well written, and the corrective actions, both short and long-term, were determined by the inspector to be comprehensive.

d. Conclusion

The VY staff took appropriate action to identify the root cause of the "A" EDG output breaker failure and to implement prompt and comprehensive corrective actions. The safety consequences were minimized as a result of the "B" EDG operability and availability. The resultant TS limiting condition for operation non-compliance was not cited because the mechanical failure was not reasonably preventable or within the control of the VY quality assurance processes. The retraction of the September 24 10 CFR 50.72 report to the NRC was inconsistent with 10 CFR 50.72 guidance. Nonetheless, the breaker problems were reported and the 10 CFR 50.73 reports were appropriate and well written.

M8.2 (Update) IFI 96-09-03: Residual Heat Removal System Pump Start Interlock

a. Background

On September 7, while control room operators were attempting to place the "D" residual heat removal (RHR) pump in a shutdown cooling configuration, the pump start interlock was not satisfied and the pump failed to start. As discussed in inspection report 50-271/96-09, the cause of the pump start failure was determined to be incorrect limit switch settings on the "D" RHR pump suction valve, RHR V10-15D. This particular limit switch problem resulted in the RHR pumps not being able to be started in the shutdown cooling mode, but did not adversely impact the emergency core cooling safety function of the RHR system.

b. Inspection Scope

The inspector reviewed LER 96-021, Inadequate procedural controls of MOV limit switch settings result in a potential common cause failure mode with the capacity to affect multiple safety significant components, dated October 7, 1996, and the supporting root cause evaluation and internal documentation.

c. Observations and Findings

The licensee's investigation revealed that the limit switches had been adjusted during implementation of a design change (EDCR 95-407) in May 1996 to standardize motor operated valve (MOV) wiring configurations. EDCR 95-407 specified that limit switch rotors #1 (valve travel open limit) and #3 ("D" RHR pump start interlock) both be set at the 95 percent valve open position. The purpose of the pump start interlock is to ensure that the pump suction valve is fully open before the pump starts. Since operation of limit switch rotor #1 causes the motor operator to stop, limit switch rotor #3 must rotate prior to, or coincident with, limit switch rotor #1. However, this basis for the rotor settings was not documented in EDCR 95-407. Furthermore, the procedure that was used to set the rotors, OP-5220, "Limitorque Operator," revision 19, did not contain sufficient guidance concerning the relative settings of valve stop and system interlock limit switch rotors. However, procedure OP-5520 did provide a generic tolerance for rotor settings of plus or minus 2 percent. Consequently, it was possible for the rotors to be set, in compliance with the procedure, such that the pump start interlock was non-functional; that is, the #1 rotor operated to stop the motor operator prior to the #3 rotor operating to satisfy the pump start interlock.

The licensee determined the root cause of this event to be, "a lack of formal MOV limit switch setpoint basis documentation." From this, it was concluded that a potential common cause failure mode existed for MOVs with permissive interlocks and standardized wiring. From a review of all valves within the scope of the licensee's Generic Letter 89-10 (Safety related MOVs) program, eight additional valves were identified as being susceptible to this problem. These valves were examined for proper control logic sequencing, and all were found to be satisfactory.

Contributing causes were determined to be inadequate written procedures and inadequate training. Corrective actions included disseminating interim guidance concerning the proper sequencing of interlock and valve travel limits, inclusion of specific guidance in future revisions of applicable procedures, and future incorporation of lessons learned from this event into MOV training.

d. Conclusions

While review of GL 89-10 program valves was an appropriate immediate response to this event, the inspector considered that screening all systems covered under the maintenance rule would have provided a more thorough scoping of the problem. The inspector noted that, as a result of this and other maintenance-related MOV problems that occurred during the 1996 outage, the licensee has initiated a self-assessment of MOV maintenance activities. Pending completion of this assessment, this Inspector Follow-up Item remains open.

M8.3 (Update) IFI 96-09-04: Alternate Rod Insertion Actuation Due To Maintenance Involving a Reactor Vessel Water Level Instrument

a. Background

On October 8, an Instrument and Control (I&C) technician was performing operations to backfill the reference leg for one of the reactor vessel wide range water level instrument detectors. This activity resulted in the reference leg for two narrow range reactor vessel level detectors inadvertently being filled. The resultant false low level signals caused an actuation of the alternate rod insertion (ARI) system. The ARI system is an anticipated transient without scram (ATWS) mitigation system that serves as a backup to the reactor protection system (RPS). The licensee notified the NRC operations center (Event No. 31118) of this inadvertent ATWS mitigation system actuation as required by 10 CFR 50.72 (b)(2)(ii).

b. Inspection Scope

The inspector reviewed the licensee's assessment of this event as documented in internal correspondences and the Event Reporting system.

c. Observations and Findings

The inspector noted that the licensee had evaluated this event as not being reportable under 10 CFR 50.73, "Licensee event report system." NUREG 1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," revision 1, states that, "invalid actuations that occur after a safety function has already been completed are not reportable. An example would be RPS actuation after the control rods have already been inserted into the core." The licensee concluded that the event was not reportable as an LER because, "all rods were already fully inserted as the plant was in a shutdown condition and reactor water level was +561 inches (cavity flooded).

The inspector considered that the event was reportable under 10 CFR 50.73. The UFSAR states that the safety objective of the RPS is to prevent, "the uncontrolled release of radioactive material from the fuel and nuclear system process barrier by terminating excessive temperature and pressure increases through the initiation of an automatic scram." The condition of the reactor at the time of the ARI system actuation was not the result of the RPS having completed its safety function, but rather of a planned manual reactor shutdown to support reactor refueling. Additionally, in an example of an ESF actuation during a maintenance activity, NUREG 1022 concludes that, "if during a planned procedure or test, the ESF actuates in a way that is not part of the planned procedure...the event would be reportable."

d. Conclusions

The inspector discussed this evaluation of the event's reportability with the licensee. The inspector noted that, because the reporting criteria of 10 CFR 50.72.(b)(2)(ii) and 50.73.(a)(2)(iv) are identical, additional licensee action is required in either case (either to withdraw the four-hour notification or submit an LER). Pending completion of the licensee's reportability determination for this inadvertent ARI system actuation, this Inspector Follow-up Item remains open.

M8.4 (Update) IFI 96-09-05: Primary Containment Nitrogen Purge System Isolation Valve Leakage

a. Background

On September 24, a combined leak rate test of containment isolation valves SB-16-19-10/11A/11B (containment nitrogen purge system inboard torus isolation and two drywell-to-torus vacuum breaker valves) indicated excessive leakage from one or more of the valves. The leakage rate could not be quantified because it exceeded the capacity of the test rig.

b. Inspection Scope

The inspector reviewed Licensee Event Report (LER) 96-025, Inadequate testing leads to misadjustment of isolation valve mechanical stop and failure to meet Technical Specification leak rate limits for containment purge isolation valve, dated October 24, 1996, and the supporting root cause evaluation and documentation.

c. Observations and Findings

The licensee's investigation revealed that SB-16-19-10 was the source of the leakage. This valve is a 18-inch air-operated butterfly valve. The cause of the leakage was determined to be that the actuator mechanical stop was not properly adjusted and prevented the valve from achieving full closure. The misadjustment had not been identified in earlier leak tests due to the test method and the valve orientation.

Previous leak tests had been performed in the non-accident direction (pressure towards containment), based on the assumption that the isolation capability of the valve was equivalent in either direction. However, in preventing the valve from achieving full closure, the actuator mechanical stop imparted a directional characteristic. Although not known by the licensee, the valve was oriented such that test pressure was assisting valve closure; there was apparently enough give in the actuator/valve for this assist to fully close the valve. For the 1996 outage, the direction of pressure application was changed to test the valve in the accident direction, as part of licensee improvements of their appendix J test program. From this direction, test pressure opposed valve closure, thus maintaining the disc unseated.

Review of maintenance history indicated that the most recent mechanical stop adjustment had been made to SB-16-19-10 in July 1978. The licensee's review also determined that the pathway leak rates associated with SB-16-19-10 had been within TS limitations and accident assumption values at all times. Thus, although the valve would not have held pressure, backup valves maintained containment integrity during the period that this condition existed.

The licensee determined that the apparent cause of this event was, "an inadequate Appendix J testing methodology, in that the testing approach was only valid if the mechanical stop was properly adjusted, and testing in the accident direction was the sole means of making that determination." Inadequate vendor information concerning the potential effect of mechanical stop adjustment on directional isolation characteristics was listed as a contributing cause.

As corrective action, SB-16-19-10 was reoriented so that pressure from containment would assist in seating the valve, and the actuator mechanical stop was adjusted to allow full closure of the valve. The valve subsequently demonstrated satisfactory performance during leak tests with pressure being applied in both the accident and non-accident directions. In addition, other containment isolation valves of similar design were inspected and verified to be oriented such that containment pressure assisted in valve seating. Documentation will be updated concerning the potential direction dependent isolation capability of containment isolation butterfly valves, and proper orientation of the valves relative to containment.

The inspector also reviewed VY Event Report 96-825 concerning this event. As in LER 96-25, the report concluded that inadequate testing was a root cause; however, it went on to conclude that poorly defined job performance standards and a lack of configuration control in valve orientation were contributing root causes. The report does not list inadequate vendor information (listed as a contributing cause in the LER) as either a root or contributing cause. Additionally, action to examine valves of similar design for proper orientation was listed as an outstanding action, to be completed during the 1998 outage.

d. Conclusions

The inspector found the above corrective actions appropriate. The licensee's deferral of the completion valve examinations until the 1998 outage was appropriate, in that, despite the potential a valve's orientation to be opposite that prescribed, the most recent Appendix J test results (with testing being conducted in the correct accident direction) demonstrate containment integrity leakage criteria remains satisfied. The inspector was informed that a supplement to LER 96-025 was being developed. Pending completion of the licensee's evaluation of this event and inspector review of the LER supplement, this Inspector Follow-up Item remains open.

III. Engineering

E1 Conduct of Engineering

E1.1 Seismic Qualification of Emergency Diesel Generator Relays

a. Inspection Scope (37551, 93702)

As a result of a recent 10 CFR 21 notification concerning the seismic qualification of ABB protective relays, Yankee Atomic Electric Corporation conducted an investigation to determine whether the problem was applicable to VY. Independent test results indicated that two relays (types CRN-1 and KLF) used in the emergency diesel generator (EDG) control cabinets did not fully meet the IEEE C37.98 requirements for seismic qualification. Specifically, if these relays were either in the energized or de-energized state at the onset of a seismic event, they would maintain continuity of function through the event. However, if required to change state during a seismic event, proper operation could not be assured. The relays at issue were the CRN-1 reverse power (anti-motoring) relay and the KLF loss of field relay.

b. Observations and Findings

The licensee evaluated the affect of this finding on EDG operability. The CRN-1 reverse power relay and the KLF loss of field relay do not serve a safety function, but rather provide protective trips for the EDGs. The relays are normally de-energized. When the associated condition is sensed, they energize to cause the EDG lockout relay to energize. The lockout relay, in turn, trips and locks out (prevents restart until manually reset) the EDG, and opens the EDG output breaker. Since the CRN-1 and KLF relays would operate satisfactorily during a seismic event while steady state (energized or de-energized), the licensee concluded that an inadvertent lockout of an EDG due to seismically induced mis-operation of the CRN-1 or KLF relay will not occur.

The conditions of reverse power and loss of field are only of concern when the EDG is operating in parallel with another power source. In performing its safety function, an EDG operates as the single power source for its associated electrical busses. Therefore, seismically induced mis-operation of the CRN-1 or KLF relay under demand-to-operate conditions is not a consideration while the EDG is performing its safety function.

The only time that the EDGs are routinely operated in parallel with another power source is during monthly surveillance testing. Under this circumstance, a reverse power condition or loss of field, coincident with a seismic event, would potentially result in failure of the associated relays to perform their protective function. The licensee evaluated the consequences of such a failure, based on a seismic event duration of 30 seconds. Given that the relays would operate properly once the seismic event ended, the licensee considered that the delay in accomplishing the protective lockout would not result in severe damage to the EDG. With respect to safety function, this scenario is no different than it would be without considering the relay failures, since a demand-to-operate condition (loss of field) would, in itself, render an isochronous EDG inoperable.

The inspector reviewed the licensee's initial operability determination and subsequent basis for maintaining operation (BMO), 96-16, "Seismic Qualification of CRN-1 and KLF Relays." The initial determination, that there were no seismic concerns associated with the relays that would prevent the EDGs from performing their design safety function, was well supported. The BMO was thorough and adequately addressed surveillance testing, an area that was not evaluated in the initial determination. The BMO recommended that the affected relays be replaced to provide additional EDG protection during surveillance testing.

c. Conclusions

Licensee investigation in response to a 10 CFR 21 notification identified and confirmed a lack of full seismic qualification of two EDG protective relays. The VY staff's evaluation that this condition, which concluded that this condition did not affect EDG operability, was prompt and thorough.

E2 Engineering Support of Facilities and Equipment

E2.1 Appendix R Compensatory Measures

a. Inspection Scope (92903)

The inspectors reviewed the adequacy and effectiveness of 10 CFR Part 50, Appendix R, compensatory measures implemented by VY for the interim period between plant restart from the Fall 1996 outage and NRC disposition of pending exemption requests. VY's evaluation of such compensatory measures and bases for providing reasonable assurance that they meet the intent of Appendix R and can achieve and maintain safe plant shutdown, in the event of any postulated fire, was provided to the NRC in letter BVY96-132, dated October 26, 1996.

b. Observations and Findings

The inspectors interviewed several posted firewatches in the seven fire areas/zones with unapproved Appendix R exemptions. The inspectors found that firewatches were properly trained and knowledgeable of their responsibilities. The responsibilities of such firewatches were to:

- monitor assigned locations for changes that could increase the likelihood or severity of a fire;

- be alert to fire symptoms so that a potential fire is discovered in its incipient stages;
- alert the control room of any fires that may occur; and
- provide fire suppression using portable fire extinguishers following control room notification and prior to arrival of the fire brigade.

The seven fire areas/zones reviewed by the inspector included: the control room; the west switchgear room including the associated battery room; cable vault area; and reactor building (RB) fire areas 1, 2, 3, and 4. This review verified that hotwork and combustible material permits were properly posted, controlled, and routinely inspected. The inspectors found that in-situ combustibles were spread evenly within the fire areas and ready access had been maintained for manual fire fighting. Good housekeeping was noted.

Additional compensatory measures established by VY and reviewed by the inspectors included enhancements to shutdown procedures, coping strategies for particular fire scenarios, and staff understanding of the bases and intent of Appendix R regulations. The inspectors noted that the actions taken by VY were the result of VY's assessment of their fire protection program, including the fire hazards analysis, safe shutdown capability analysis, and safe shutdown implementing procedures. The licensee had established four independent assessment teams to evaluate the fire protection program comprehensively.

The inspectors found that plant post-fire safe shutdown strategies for the interim operating period were fully addressed in the emergency operating procedures (EOPs) and fire event procedure OP-3126, Revision 14, "Shutdown Using Alternate Shutdown Methods." The inspectors noted that an additional licensed operator had been assigned to each operating crew to ensure timely implementation of actions required to be performed in accordance with OP-3126 and VY Standing Order No. 17. Further discussion of this issue is made in Section E3.1. The EOPs were symptom-based procedures that directed operator response to abnormal plant condition procedures regardless of cause. The inspectors found that VY's approach to EOPs had been found acceptable by the NRC per the "Safety Evaluation of BWR Owners Group - Emergency Procedure Guidelines, Revision 4, NEDO-31331, March 1987," dated September 12, 1988.

c. <u>Conclusions</u>

The inspectors concluded that VY had developed and implemented proper Appendix R compensatory measures. These compensatory measures, administrative controls, and installed fire detection, suppression, and protection, and safe shutdown enhancements as well as the augmented awareness demonstrated by personnel, provided good assurance that VY could achieve and maintain safe plant shutdown in the event of any postulated fire. Therefore, the intent of Appendix R was satisfied as supported by the compensatory measures and enhancement of previously established defense-in-depth design of the plant. The results of this inspection were communicated to senior NRC management in Region I and at Headquarters on October 28, 1996, prior to plant restart on October 30, 1996.

E3 Engineering Procedures and Documentation

E3.1 Appendix R Corrective Action Review

a. Inspection Scope (64150)

The inspectors reviewed VY's ongoing 10 CFR Part 50, Appendix R corrective actions taken in response to previously identified fire-induced hot short vulnerability issues associated with the emergency diesel generator (EDG) and other support systems, requiring operator actions at the Appendix R alternate shutdown panels. These actions are necessary to safely shutdown the plant in the event of a fire in either the control room or cable vault rooms, as documented in inspection report 95-26.

b. Observations and Findings

During the August 1996 follow-up inspection, documented in inspection report 96-08, section E1.2, the inspector found that the licensee had completed the designs of several Appendix R modifications to enhance the reliability of Appendix R systems, specifically, reactor core isolation cooling (RCIC) and automatic depressurization systems (ADS). However, the installation and testing work remained outstanding and was planned to be completed prior to restart, following the Fall 1996 refueling outage.

During this inspection, the inspectors found that the licensee had implemented design changes per Modification No. EDCR 96-401 to enhance the reliability of Appendix R systems, including the "A" EDG system. These design changes added sets of redundant fuses in various control panels for Appendix R support systems, including the "A" EDG. In addition, sets of pre-staged fuses were available for fuse replacements in other selected support systems. Per the new design, the previous system fuses and postulated fire-induced damaged circuits from hot shorts would be isolated, and the new set of redundant fuses and associated circuits, including the "A" EDG system circuits, would be manually connected to these systems by operating switches installed on local switchgear compartments and Appendix R alternate shutdown panels. These actions would alleviate concern for postulated damage to the fuses and circuits from fire-induced hot shorts. The inspectors verified the adequacy of installation and post-modification test results. No concerns were identified.

Alternate Shutdown

The inspectors' review of the licensee's FSAR, Section 8, and the established alternate Appendix R shutdown procedure, OP 3126, "Shutdown Using Alternate Shutdown Methods," revision 14, indicated that VY relies on onsite AC power supplied by the "A" EDG to safely shutdown the plant in the event of a fire in either the control room or cable vault areas. Per the established shutdown procedure, reactor shutdown is accomplished by operators from the alternate shutdown panels using a safety relief valve and the low pressure coolant injection (LPCI) system to control reactor level and pressure following the initial transient. Next, the residual heat removal (RHR) system would be used to cool the torus and when possible, for shutdown cooling of the reactor. In this event, the "A" EDG would be used to supply AC power to safety bus 4 after bus 4 would have been isolated from offsite AC power sources. The inspectors also verified that the procedural steps, as outlined in the established shutdown procedure, could be completed appropriately under such postulated fire events as presented in the Appendix R rule.

Shutdown Procedure Enhancements

The inspectors found that VY had supplemented their minimum control room crew of operators with an additional licensed control room operator (ACRO). The need to supplement operating crews was recognized by VY and documented in Event Report (ER) No. 95-0533 and Licensee Event Report (LER) No. 95-14, Supplement 3, dated September 4, 1996. Upon this discovery by VY that the time to core uncovery during alternate shutdown (without high pressure make-up inventory) was less than previously identified, the licensee took corrective action to enhance the shutdown procedure. The original 1981 VY calculation (reference NED-81-486) determined that 43.7 minutes existed prior to core uncovery following a reactor scram. Timelines were developed by the Operations staff demonstrating that RCIC could be initiated within this time from the alternate shutdown panel, satisfying Appendix R requirements including the use of high pressure injection. However, recent Appendix R reviews performed by VY could not find the calculation, and alternate methods used by VY to validate 43.7 minutes could not duplicate this result. Although the assumptions, modeling, method of review conducted, and results of this calculation were documented in VY Memorandum NED-81-486, dated July 15, 1981, VY appropriately performed a reanalysis and took immediate corrective action by posting firewatches during the interim (also reference VY's March 12, 1996 response letter to Notice of Violation, NRC Inspection Report No. 50-271/95-26, EA No. 95-268, dated February 13, 1996).

VY's Appendix R reanalysis for determining core uncovery time concluded that 22.5 minutes existed prior to core uncovery. This reanalysis provided the bases and timelines for both core uncovery and peak fuel cladding temperature increases following core uncovery. The inspectors noted that VY conservatively and appropriately defined the time of core uncovery as the time when the two phase coolant flow inside the core shroud eventually drops to the top of the active fuel. This time was calculated as the boil-off progressed and the downcomer coolant level (outside the shroud) reached an elevation equal to the top of fuel. However, the inspectors noted that the actual level inside the shroud would be higher because of the two-phase mixture present inside the core. Based on the results of this reanalysis, VY had implemented several design changes, reassigned personnel, eliminated unnecessary actions, and conducted operator training on the enhanced operator actions per OP 3126, including the issuance of Standing Order No. 17, Revision 18, to ensure that the reduced time limit to restore AC power and the initiation of RCIC could be met. The inspectors noted that the bases used in this reanalysis was similar to VY's symptom-based emergency operating procedures that allowed for vessel level to drop below the top of fuel level, as approved by the NRC. The inspectors determined that the licensee's corrective actions were extensive and proper as discussed in section E2.1, "Appendix R Compensatory Measures."

The inspectors conducted a walkdown and verified that manual actions required by the shutdown procedure could be performed adequately from the alternate shutdown panels using the "A" EDG. The inspectors noted that VY had requested an exemption from the requirements of Appendix R, Section III.L, "Alternative and Dedicated Shutdown

Capability," on April 4, 1996. This exemption request identifies the use of the Vernon tie line as the preferred AC power source instead of the "A" EDG. The inspectors found that the licensee planned to modify the existing shutdown procedure following final NRC approval of the exemption request, as discussed in LER 95-14-03, dated July 25, 1995, VY letter (BVY 96-117) to the NRC, dated October 8, 1996, and NRC letter to VY, dated October 30, 1996.

Tie Line Testing

The inspectors performed a review of the status of the Vernon tie line design change. As discussed in the FSAR, the inspectors noted that the Vernon tie line power source had been approved as the station blackout (SBO) power source per 10 CFR 50.63 as documented in inspection report 95-13. The Vernon tie line was approved and used only as a back-up power supply for SBO and not credited to satisfy Appendix R requirements at that time. However, VY had implemented a design change (No. EDCR 96-402) that upgraded the Vernon tie line capacity, loss of normal power (LNP) protective circuitry, and ammeter cables to prevent any inadvertent actuation of overcurrent relays or spurious actuations of the tie line breaker resulting from fire-induced hot shorts.

The inspectors performed a walkdown of the changes installed and verified that the design changes were complete and that functional testing had been performed appropriately. The inspectors also reviewed the tie line connection point at the Vernon switchyard. During this review the inspectors found that the temporary connection, discussed in inspection report 95-13, had been made permanent and that the licensee performed surveillance testing of the tie line capacity in 1996, to assure the tie line was capable of carrying the required loads. The inspectors reviewed the results of the capacity testing performed by VY and verified it was in accordance with NRC safety evaluation report (SER), dated June 1, 1994.

The review indicated the line was successfully tested with a load of 2441 kW, approximately 80 percent of the proposed Appendix R rated capacity, which was the maximum load available to be transferred on the bus during outage conditions. The inspectors noted that the licensee had been performing maintenance and testing on the tie line transformer and cable also. The inspectors' review of the transformer test results did not identify any concerns. In addition, VY implemented OP 4142, "Vernon Tie Surveillance," revision 6, to test the tie line load capacity and the alternate shutdown control circuitry of the tie line circuit breakers. The inspectors noted this surveillance test was required to be performed each operating cycle per the surveillance procedure.

The inspectors further noted that: the installed tie line feeder cable was installed underground for enhanced reliability; the rated transformer capacity (3200 kW at 0.85 power factor) exceeded the maximum calculated loads for SBO (2762 kW) and proposed Appendix R (2700 kW) loads; tie line testing was performed appropriately per the SBO SER requirements; and the components of the line also had a higher rated capacity than both the SBO and Appendix R loads.

c. Conclusions

The inspectors concluded that the licensee had correctly addressed the Appendix R hot short concerns associated with the "A" EDG and associated Appendix R systems and had enhanced the overall system ability to shutdown the plant. In addition, the licensee was appropriately using the "A" EDG as the preferred AC power source per the established plant safe shutdown procedure and approved operating license. However, discussions with the licensee revealed that VY would prefer to use the Vernon tie line as the Appendix R power source, in the event of a fire in either the control room or cable vault areas, based on its reliability and simple and timely operational alignment. The use of the tie line is the subject of a pending exemption request submitted by the licensee for NRC staff review and approval.

E8 Miscellaneous Engineering Issues (92902)

E8.1 (Closed) IFI 95-25-02: High Pressure Coolant Injection Operation and Testing

During an earlier inspection, the VY staff was unable to readily retrieve the high pressure coolant injection (HPCI) system net positive suction head (NPSH) calculation for both the condensate storage tank (CST) and torus suction sources to the HPCI pump. Since that inspection period, the VY staff has retrieved and re-examined the original NPSH calculations (Technical File 4.8) which assume no pressure in the torus and torus water temperature at its maximum operating design limit (140 degrees F). The VY staff verified sufficient HPCI system NPSH was available under all design conditions. As previously concluded, the inspector identified no concerns regarding HPCI system operability. During this inspection period, the inspector confirmed that the VY staff maintained appropriate HPCI system design calculations and that those design calculations were consistent with accident analysis assumed system response. This inspection followup item is closed.

E8.2 (Closed) URI 95-25-05: HPCI Suction Valve Logic Design Observation

a. Background

During an earlier inspection period, the inspector reviewed the VY staff's implementation of a modification to the high pressure coolant injection (HPCI) system which resulted in some unanticipated system responses. Upon closer examination of the HPCI system design and operation, the inspector questioned whether the HPCI system suction transfer logic circuitry and components were required to meet single failure criteria, and whether primary containment integrity is potentially compromised during the time period that the HPCI system suction is shifting from the condensate storage tank (CST) to the torus. These questions were shared with the VY staff and an engineering staff review was initiated via the Event Report system.

b. Inspection Scope

The inspector examined VY's response to the above questions as documented in Event Report (ER) No. 96-0033, completed November 9, 1996, Performance Engineering Self-Assessment Report, dated March 6, 1996, and discussed the conclusion with the responsible performance engineer.

c. Observations and Findings

Inspector examination of Section 6, Reactor Core Standby Cooling System and Appendix F, conformance to AEC General Design Criteria, of the VY Updated Final Safety Analysis Report (UFSAR) and the licensee's above stated responses identified that the HPCI system, and its attendant sub-systems, are not designed to be single failure proof. However, UFSAR, Appendix F specifically states that HPCI, in conjunction with the automatic depressurization system (and the residual heat removal and core spray systems) satisfy General Design Criterion 35 and are single failure proof. Thus, the HPCI system is not a stand-alone high pressure emergency core cooling system.

The resolution of the question concerning the potential for compromising containment integrity during the interim period that the HPCI system suction is swapping from the CST to the torus required a more detailed analysis. As previously identified, with the suction isolation motor-operated valves open (23V-17 from the CST, and 23V-58 and 23V-57 from the torus), a water-filled pathway between the torus and CST (vented to the atmosphere) is established. However, both branches of the HPCI system suction line have check valves (23V-61 from the torus and 23V-32 from the CST) to prevent possible cross-flow or cross-contamination. The inspector notes that prior to the HPCI system pushbutton modification, all of the above mentioned valves were tested via the VY Inservice Testing (IST) Program. However, the check valves were tested in the open direction only. Based upon the March 6, 1996 Performance Engineering self-assessment, check valve closed direction testing was satisfactorily conducted and incorporated into the IST program (quarterly radiographic testing is performed).

The VY staff evaluated the possible HPCI system failures and postulated accident scenarios which could potentially result in a torus to atmosphere vent pathway via the HPCI suction line, but identified no viable scenario. The inspector independently examined the potential torus to atmosphere vent pathway scenarios and likewise concluded that HPCI system design would prohibit such an event. The bounding scenarios analyzed are summarized below:

- 23V-57 (normally closed) and 23V-58 (normally closed) fail open (single active failure - loss of control logic power causes both valves to go open) with 23V-17 (normally open) remaining open. The CST suction line check valve, 23V-32, remains functional and prevents reverse flow to the CST. The inspector notes that this scenario is the same as the event of December 7, 1995 documented in inspection report 95-25, section 4.1.

The inspector identified that UFSAR, section 7.3.4.3, states that "process pipe lines that penetrate the primary containment but do not communicate directly with the reactor vessel, the primary containment free space, or the environs, have at least one Class C isolation valve located outside the primary containment which may close by process action (reverse flow) or by remote manual operation. Valves 23V-57, 23V-58, or 23V-32 satisfy this function. However, the inspector also notes that UFSAR, section 7.3.4.5, states that the HPCI and reactor core isolation cooling isolation valves, due to their service, are exceptions to the typical system isolation design and use a "non-fail-safe" logic (when isolation is not required, sensor and trip contacts are normally open, and channels and trip logics are normally de-energized).

- 23V-32 fails open (single active failure) with 23V-57 and 23V-58 remaining operable and closed. The torus to CST pathway remains blocked via the two closed torus suction line motor-operated isolation valves.

The inspector notes that for the design basis loss of coolant accident (double ended guillotine break of a recirculation line), the HPCI system will not be initiated due to the rapid depressurization of the reactor vessel and subsequent core cooling provided by the low pressure emergency core cooling systems (ECCSs). However, postulated torus pressures could reach approximately 42 psia (reference UFSAR, Figure 14.6-5). This pressure is more than sufficient to overcome the available head of the CST to the HPCI pump suction (22.6 psia), a differential pressure of 19.4 psi, but the blocking valves prevent flow.

- Small break LOCA with HPCI system operating and CST to torus suction swap in-progress.

IST results indicate that the time of valve stroke (23V-57/58-150 seconds and 23V-17-158 seconds) results in all three suction valves partially open for approximately 150 seconds. During this time period, assuming the torus is pressurized and CST suction line check valve 23V-32 has failed open, the preferential fluid flow path would be to the suction of the HPCI pump vice to the CST.

c. Conclusion

The HPCI suction line, by design, does not provide a pathway for post-LOCA primary containment airborne contaminates to communicate to the atmosphere via the condensate storage tank vent. The VY staff analysis of these two HPCI system issues was thorough and well documented. Unresolved item 95-25-05 is closed.

E8.3 (Closed) URI 96-05-05: RHR Minimum Flow Valve and the LOCA Failure Analysis

The licensee's identification of the residual heat removal (RHR) system minimum flow valves' single failure vulnerability with respect to the impact on the loss of coolant accident (LOCA) analysis was closely examined in inspection report 96-07. As a consequence, this issue was the subject of a notice of violation and imposition of a civil penalty (reference Enforcement Action No. 96-210, dated August 23, 1996). Inspector followup system (IFS) tracking number 96-210-01013 was assigned to this violation. This unresolved item is administratively closed.

E8.4 (Closed) URI 96-06-01: Appendix J Testing of Certain Valves Has Not Been Conducted and Specific Exemption Requests Are Pending Licensee Submittal and NRC Staff Review

As documented in inspection report 96-09, section E1.1, the VY staff addressed this previously identified Appendix J concern by re-designating the containment isolation valves of interest in the core spray (CS) and residual heat removal (RHR) systems. The licensee did not seek exemption for these or any other containment isolation valves previously untested per Appendix J requirements. Inspection report 96-09 updates the Appendix J concerns addressed in unresolved item 96-06-01 and identifies the need for NRR staff review of the safety evaluation (10 CFR 50.59) conducted by VY to substantiate the re-designation of the CS and RHR containment isolation valves. This unresolved item is administratively closed and the NRC staff review and followup of the re-designation of the CS and RHR containment isolation valves is being tracked by unresolved item 96-09-07.

IV. Plant Support

F1 Control of Fire Protection Activities

F1.1 Fire Protection Program Ownership

a. Inspection Scope (64704)

The inspectors evaluated the effectiveness of VY's corrective actions taken to address fire protection program ownership issues including poor management oversight previously identified by VY and the NRC. This lack of adequate program oversight contributed to numerous fire protection weaknesses and the failure by the licensee's staff to understand the program, including 10 CFR Part 50, Appendix R requirements, to follow up on identified open items, and to maintain the program in accordance with licensing and design basis parameters. These failures resulted in escalated enforcement action as documented in inspection report 95-26 and were attributed to poor program oversight since the Appendix R rule implementation in 1980.

b. Observations and Findings

The inspectors found that VY had initiated independent reviews to evaluate the fire protection program comprehensively, conducted benchmarking of several other nuclear power plant fire protection programs, enhanced personnel training and procedures, applied significant resources to correct deficiencies, reconstituted licensing and relevant design bases including commitments, and taken corrective actions to resolve hardware, programmatic, and oversight issues. The inspectors noted that such actions were proper and demonstrated a broad management commitment to the improvement process and the fire protection program.

Corrective actions included the implementation of compensatory measures to achieve full compliance with requirements as detailed in VY's violation response to the NRC, dated March 12, 1996. Specifically, VY has reduced the levels of management to improve the interaction between design engineering and the site and better defined individuals' responsibilities as presented in "VY Fire Protection Plan," revision 13. Fire protection program goals were well defined and the support provided by engineering and operations departments to achieve program compliance were good.

The inspectors found that additional corrective actions included the assignment of a lead fire protection coordinator to provide full-time onsite direction of program activities. Additionally, other onsite dedicated support personnel had also been assigned to the site until all program reviews and corrective actions are complete and a permanent full-time fire protection engineer had been selected to maintain the program. During the interim, the lead fire protection coordinator will be the one clear program owner, as described in the fire protection plan. The knowledge of NRC requirements and VY specific fire protection information by staff interviewed during this inspection was extensive and very noteworthy. VY expects all outstanding fire protection issues to be resolved and compliance achieved by the end of 1997.

Additional actions taken by VY to prevent recurrence of previous management oversight concerns included:

- issuance of a bi-weekly project progress report issued to plant management by the lead;
- the fire protection project team will make a monthly report at the Engineering Projects meeting;
- prohibition of changes to Appendix R related compensatory firewatch measures without the Plant Oversight Review Committee (PORC) review and the plant manager's approval; and,
- scheduling of more frequent and in-depth self-assessments and independent assessments to be conducted and reviewed by the QA organization.

c. Conclusions

The inspectors concluded that rigorous efforts had been taken by the licensee and proper corrective actions were planned or implemented to address previous program ownership issues associated with fire protection. The inspectors determined that actions taken by VY to improve program oversight and staff understanding of NRC requirements, licensing and design bases information, and commitments to the NRC were effective and the VY staff's understanding of fire protection was extensive and noteworthy, based on this review.

F8 Miscellaneous Fire Protection Issues (71750, 92904)

F8.1 (Closed) URI 96-03-06: Switchgear Rooms' Carbon Dioxide Suppression Systems Declared Inoperable Due To Insufficient Post-Modification Testing

As previously documented, the VY staff identified during their programmatic review of their Appendix R and fire protection programs that no post-modification testing results could be found to demonstrate the adequacy of the East and West switchgear rooms' carbon dioxide (CO_2) suppression systems. Compensatory fire watches were established pending completion of testing to demonstrate operability.

Following completion of testing (using an alternative method vice a full CO_2 discharge test) on both East and West switchgear room suppression systems, the VY staff concluded that neither CO_2 suppression system satisfied its design basis and reported these results to the NRC (Event No. 30892, LER No. 96-20) on August 19, 1996. The inspectors conducted a detailed followup of this testing and the VY staff's actions, as documented in inspection report 96-08, section M2.1. An unresolved item was assigned to track the licensee's resolution of this newly identified design concern (96-08-01). As a result, unresolved item 96-03-06 is administratively closed and inspector review of the switchgear CO_2 suppression system design concern will continue to be tracked by unresolved item 96-08-01.

P5 Staff Training and Qualification in EP

At 9:32 a.m. on December 4, 1996, the control room staff notified the Headquarters Duty Officer per 10 CFR 50.72 (Event No. 31403) that the emergency response public notification system would be out of service for approximately nine hours (emergency response capability degraded) during the performance of preventive maintenance. At 10:25 a.m. on December 4, the control room staff retracted their 9:32 a.m. notification after having verified that the public notification system remained operable via its backup system. The resident inspectors were informed of these notifications and determined that the licensee staff continues to have some minor communications and public notification systems operating knowledge problems with both the maintenance contractor staff and control room staff. This systems operator knowledge weakness was reviewed previously and documented in inspection report 96-02, section 5.2. VY's efforts to improve operator knowledge of the public notification system has not been entirely effective. However, the safety consequence of this operator knowledge deficiency was minor.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors met with licensee representatives periodically throughout the inspection and following the conclusion of the inspection. 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 Management Meeting Summary

On October 21, VY managers met with the NRC headquarters and Region I staffs in Rockville, MD to discuss the status of Appendix R corrective actions as they related to restart readiness. A report on that meeting will be docketed under separate correspondence.

X3 Review of Updated Final Safety Analysis Report (UFSAR)

A recent discovery of a licensee operating its facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and 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. No discrepancies were noted.

INSPECTION PROCEDURES USED

71707	Plant Operations
62707	Maintenance Observations
61726	Surveillance Observations
37551	Onsite Engineering
71750	Plant Support Activities
92904	Followup - Plant Support
64704	Fire Protection Program
64150	Triennial Postfire Safe Shutdown Capability Reverification
92903	Followup - Engineering
93702	Onsite Response to Events
92902	Followup - Maintenance
92700	Onsite Followup of Written Reports of Non-routine Events

ITEMS OPENED, CLOSED, AND DISCUSSED

CLOSED

IFI 95-25-02	High Pressure Coolant Injection Operation and Testings
URI 95-25-05	HPCI Suction Valve Logic Design Observation
URI 96-03-06	Switchgear Rooms' Carbon Dioxide Suppression Systems Declared Inoperable Due To Insufficient Post-Modification Testing
URI 96-05-05	RHR Minimum Flow Valve and the LOCA Failure Analysis
URI 96-06-01	Appendix J Testing
IFI 96-09-02	"A" EDG Output Breaker Closure Mechanism Failure

DISCUSSED

IFI 96-09-03	Residual Heat Removal System Pump Start Interlock
IFI 96-09-04	Alternate Rod Insertion Actuation Due To Maintenance Involving a Reactor Vessel Water Level Instrument
IFI 96-09-05	Primary Containment Nitrogen Purge System Isolation Valve Leakage

OPEN

IFI 96-10-01	Performance of On-line Electrical Bus Maintenance

PARTIAL LIST OF PERSONS CONTACTED

R. Wanczyk, Plant Manager
G. Maret, Operations Superintendent
E. Lindamood, Director of Engineering
L. Doane, Operations Manager
M. Watson, I&C Manager
F. Helin, Reactor Engineering Manager
M. Desilets, Radiation Protection Manager
S. Skibniowsky, Chemistry Manager
G. Morgan, Security Manager

LIST OF ACRONYMS USED

VY	Vermont Yankee
TS	Technical Specifications
HPCI	High pressure coolant injection
UFSAR	Updated Final Safety Analysis Report
CST	Condensate storage tank
LOCA	Loss of coolant accident
ECCS	Emergency core cooling system
RHR	Residual heat removal
CS	Core spray
EDG	Emergency diesel generator
LER	Licensee Event Report
SBO	Station blackout
SER	Safety evaluation report
LNP	Loss of normal power
EOPs	Emergency Operating Procedures
RB	Reactor building
NPSH	Net positive suction head
ACRO	Additional licensed control room operator