U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 85-08

Docket No. 50-271 License No. DPR-28

Licensee: Vermont Yankee Nuclear Power Corporation
RD 5, Box 169, Ferry Road
Brattleboro, Vermont 05301

Facility Name: Vermont Yankee Nuclear Power Station

Inspection at: Vernon, Vermont

Inspection Conducted: February 5 - March 4, 1985

Inspectors: William J Raymond 4/1/85
W. J. Raymond, Senior Resident Inspector date

William J Raymond 4/1/85
for M. H. McBride, Resident Inspector date

Approved by: J. E. Tripp 4/10/85
W. E. Tripp, Chief, Reactor Projects date
Section 3A, Projects Branch 3

Inspection Summary: Inspection on February 5 - March 4, 1985 (Report No. 50-271/85-08)
Areas Inspected: Routine, unannounced inspection on day time and backshifts by two resident inspectors of: action on previous inspection findings; physical security; routine power operations, including logs, records and operational status of safety systems; maintenance activities; surveillance activity; operational events followup; status of piping analysis programs; licensee event report 84-11; and, fire water system controls and the status of modifications to meet Appendix R requirements. The inspection involved 135 hours on site.

Results: Operational status reviews identified no conditions adverse to safe operation of the facility. Actions to install modifications to meet Appendix R requirements were completed during the period, but further modifications and exemptions were identified as a result of the recently completed fire hazards analysis. One concern identified during the inspection included the failure to revise and reissue operating and surveillance procedures following the completion of fire system modifications in accordance with design change 84-03 (VIO 85-08-01 in section 6.5).

DETAILS

1. Persons Contacted

Interviews and discussions were conducted with members of the licensee staff and management during the report period to obtain information pertinent to the areas inspected. Inspection findings were discussed periodically with the management and supervisory personnel listed below.

Mr. D. Reid, Operations Superintendent
Mr. J. Pelletier, Plant Manager
Mr. R. Wanczyk, Technical Services Superintendent

2. Status of Previous Inspection Findings

2.1 (Closed) Follow Item 83-01-06: QA Dispositioning of Fuel Fabrication Error. The inspector reviewed Nonconformance Report 83-03 dated February 8, 1983 and Audit Report VA 037GE 027. The OQA auditors reviewed the causes of the incident during a visit to the Wilmington fuel facility on February 2-4, 1983. GE developed a detailed chronology to trace and identify the causes for the errors that resulted in fuel pins manufactured with incorrect end plug numbers. The audit verified that the fuel rods met all applicable requirements except for the identification numbers on the 10 end plugs. GE's corrective actions were reviewed and found acceptable to prevent recurrence. The final disposition of NCR 83-03 was to accept the fuel for use "as is". This item is closed.

2.2 (Closed) Follow Item 82-21-01: Control of Fire Water System Valves. The alignment of the fire water system valves was subsequently reviewed by the inspector during routine plant inspections. Additionally, a detailed valve lineup verification was completed in accordance with OP 2186 during this inspection and no valve alignment discrepancies were identified. The control of fire water system valve lineups per OP 2186 appears to be adequate. This item is closed.

2.3 (Closed) Follow Item 83-26-02: Alternate Shutdown Procedure Review. The alternate shutdown panels were declared operable and system procedures were issued in August, 1984. NRC review of the alternate shutdown procedures is documented in NRC Region I Inspection Reports 84-21 and 84-26. This item is closed.

2.4 (Closed) Unresolved Item 80-13-04: T-Quencher Weld Repair. This item was open pending NRC review of the repair and final acceptance of the T-quenchers for use in the torus, and NRC review of the classification and QA requirements. The repair of the T-quencher defects was reviewed by the NRC as documented in NRC Region I Inspection Report 80-16. The defects were repaired by either removing the defect and rewelding, or complete removal of the end caps and rewelding. The repaired T-quenchers met the ASME code requirements for safety class 2 piping and were acceptable for use in the torus. Procurement of the components under ASME III Subsection ND, and then upgrading the components to subsection NC classification following satisfactory completion of the required non-destructive examinations was acceptable. This item is closed.

2.5 (Closed) Deficiency 80-12-02: Failure to Maintain Records of Maintenance Activities. Work control procedure AP 0021, Maintenance Requests, was changed in Revision 12 on October 17, 1984 to provide a means to document second level supervisor surveillance of maintenance activities in progress. Form VYAPF 0021.02 is used to document supervisor observations and to track identified deficiencies and corrective actions. The inspector noted that licensee personnel used the form during inspector reviews of maintenance activities on previous routine inspections. This item is closed.

2.6 (Open) Unresolved Item 80-22-04: Seismic Analysis for IEB 79-02 and 79-14. The licensee's plans and schedules for completing IEB 79-02/14 analyses and base plate flexibility evaluations were reviewed by the NRC staff and found acceptable, as documented in NRC Region I Inspection Report 81-15. By letters FVY 83-16 dated March 1, 1983 and FVY 84-67 dated June 27, 1984, the licensee informed the staff of the status of the Vermont Yankee Seismic Piping Reanalysis Program which was initiated by the licensee in response to the concerns expressed in I&E Bulletins 79-02 and 79-14, and would resolve the remaining issues associated with the bulletins. The program constituted a self-imposed upgrade of the original seismic analyses completed for the plant. The program was outlined in a letter dated July 25, 1980 and has been underway since then. The reanalysis program is discussed further in paragraph 10 below.

In his June 27, 1984 submittal, the licensee stated that the engineering activities for the Seismic Piping Reanalysis Program were scheduled so as to complete all piping analyses and pipe support designs related to the original seismic supports with base plates by the end of 1984. The remaining pipe support design and analysis to complete the program would be completed during 1985. The YAEC Engineering Project Manager for Vermont Yankee informed the inspector that the engineering activities will be completed on schedule by April 1, 1985. An engineering review of the analyses completed to meet the IE Bulletins requirements will be conducted during a special NRC inspection scheduled in April, 1985. This item remains open pending completion of the special inspection to review the engineering analyses.

2.7. (Closed) Follow Item 82-16-04: Missed Surveillances. The number of occurrences where surveillance tests were not performed due to either scheduling or other personnel errors was reviewed during routine inspections and the most recent SALP evaluation period. The number of similar events identified for the period of May 1, 1983 to October 31, 1984 was five. The number of surveillance tests missed is considered insignificant in comparison to the number of tests performed on an annual basis. There are no indications that an adverse trend has developed in the area of missed surveillance tests. However, the recurrence of this type of error is of concern to the NRC as it is related to the broader scope problem of personnel errors during the performance of routine duties and adherence to established procedures. NRC concerns in this area are tracked by inspection item 84-21-14. This item is closed.

2.8 (Closed) Unresolved Item 82-21-05: Review of Containment High Range Radiation Monitors. The NRC completed a detailed technical review of the containment high range radiation monitors during Inspection 84-11. Resolution of outstanding technical issues regarding the conformance of the design and installation with the

requirements of NUREG 0737 Item II.F.1, including whether the detectors are "widely separated", is being tracked by Inspection Item 84-11-09. This item is closed.

2.9 (Closed) Follow Item 83-09-03: Effectiveness of Fire Prevention Controls. Fire protection and housekeeping controls were continually reviewed during subsequent routine inspections inclusive of periods when the plant was in an outage. No problems were noted indicative of an adverse trend in the effectiveness of fire prevention controls. This item is closed.

2.10 (Closed) Deviation 84-02-02: Employee Training for Cask Shipments. The licensee's initial response to this item was provided in letter FVY 84-44 dated May 8, 1984. Supplemental information on this item was also provided in letter FVY 84-113 dated September 24, 1984 and the training provided for maintenance personnel on the FSV-1 shipping cask was discussed in a meeting with NRC Region I staff on September 4, 1984. The inspector noted that procedure DP 0204, Maintenance Department Training, was changed in Revision 4 dated January 19, 1984 to better document on-the-job training for maintenance personnel. The NRC withdrew this deviation in a letter to the Manager of Operations dated November 1, 1984. This item is closed.

2.11 (Open) Follow Item 83-17-10: Service Water System Performance. A meeting was held with the Operations Superintendent on February 15, 1985 to discuss several issues regarding operation with the service water system cross tied to the fire water system through valve SW-8. The discussion included a consideration of Appendix A to 10 CFR 50, Criterion 44, the use of manual isolation valves between safety and non-safety class systems, and the interface between seismic and non-seismic systems.

The intake structure and portions of the service water system in it are seismically qualified. The fire water system is not seismically qualified and there are no plans to address its seismicity in the seismic upgrade program for the station. The inspector reviewed the service and fire water systems inside the intake structure and noted no differences in the type and quantity of supports used on both systems. The acceptability of the potential for interaction between the two systems during a seismic event was discussed. The licensee stated that, as described in FSAR Section 10.8, the design basis for the seismically qualified Alternate Cooling System is to provide an adequate heat sink to remove sensible and decay heat from the primary system so that the reactor can safely be shutdown in the event of a loss of Vernon Pond. Any postulated failure of the service water system due to interaction with the fire water system would be less limiting than the total loss of the pond. Thus, safe shutdown is assured. Based on the above, no safety concerns were identified concerning operation with the service and fire water systems cross-tied through SW-8.

The inspector asked whether a formal safety evaluation in accordance with 10 CFR 50.59 had been completed for the operational mode with SW-8 open. None could be identified. However, procedure OP 2181 was reviewed and approved by the Plant Operations Review Committee and provides for temporary cross connection of the service and fire water systems through SW-8 as an abnormal operational mode to

conduct certain fire system tests. The inspector stated that the licensee should address the operational mode with SW-8 open in either a safety evaluation and/or a procedure change.

The inspector stated that this item will remain open pending further review by the NRC staff of the licensee's actions.

2.12 (Closed) Unresolved Item 84-21-09: Diesel Generator Relay Failure Mechanism. The licensee installed new commercial grade SA-1 relays with a design that does not use zener diodes for surge suppression circuit in the operating circuit. Class 1E SA-1 relays have a lead time of about 1 year and will be installed when available.

No further examinations or evaluations were done on the failed diode sent to NRC Region I. The licensee completed a failure analysis on the other failed zener. The analysis results were documented in a test report by Associated Testing Labs of Massachusetts. The report described the results of a destructive examination of the IRC 6815 diode, along with 2 equivalent Motorola IN 3051A diodes for comparison. The laboratory findings and conclusions are summarized below.

The zener diode was used with a silicone controlled rectifier (SCR) in the SA-1 circuit in a manner that the SCR carries the bulk of the shunt current while the zener acts as the surge detector. The zener supplies gate voltage to the SCR when the zener voltage is exceeded, which turns on the SCR to shunt the surge current to ground.

The zener passed fine and gross leakage tests on its hermetic seal. The zener was examined microscopically after cross-sectioning and found shorted internally with globs of solder evident. The solder was fatigued to the degree where its thermal conductivity degraded, which caused the average temperature of the diode chip to increase. Since the zener breakdown voltage decreases as its temperature increases, a point was reached where the SCR failed to turn on, and the diode carried more and more current until a level of power was reached which caused the diode to fail. Evidence of the postulated failure mechanism was provided by micro-photographs contained in the report.

The licensee reviewed the laboratory report and concluded that the analysis findings supported the previous conclusions regarding the SA-1 relay failure, namely, that the diode failures probably resulted from either normal end-of-life or from accumulative damage from normally experienced switching transients within the DC system. The licensee determined there was sufficient justification to conclude that the failure of both SA-1 relays within 12 hours of each other in October, 1984 was not the result of any other external or internal common mode failure mechanism.

The inspector requested a copy of the laboratory failure report for transmittal to NRC Region I. The licensee stated that a copy of the report would be provided at a later date. This item is closed.

2.13 (Open) Unresolved Item 85-02-02: Resolution of Instrumentation Problems Caused by EQ-Beta Shields. Beta shields installed as part of an Environmental

Qualification (EQ) program upgrade during the 1984 refueling outage have caused apparent cross circuit connections on ECCS instrumentation channels. The cross connections are caused due to crimping of the channel wire bundles by the shields. Both the A and B ECCS instrumentation channels were reviewed for continued satisfactory operation during the inspection period to verify no adverse trends were apparent due to ground problems caused by the EQ-beta shields. No problems were identified. The status of the instrumentation systems was also reviewed during surveillance testing, and in meetings with the Instrument and Control personnel.

A problem on the B ECCS system, located on the South side of the Reactor Building 280 foot elevation, is manifested by a ground on the associated charger. The licensee has measured a 2K-3K ohm resistance between the positive side of the 24 volt power supply and station ground. The negative side of the supply is unaffected and the power supply is considered fully operable. There has been no anomalies observed in the operation of B side instrumentation either during routine testing or normal operations.

A problem on the A ECCS system, located on the North side of the Reactor Building 280 foot elevation, is manifested by an interaction between level channel LT 2-3 73B and pressure channel PT 2-3-52D, that is observable only when either channel is resetting after reaching its trip setpoint during channel testing. The A side problem was reviewed in detail during a meeting with the I&C Supervisor. No unsafe conditions were identified. Continued operation with the A side problem was considered acceptable since: (i) the A system channels have been demonstrated capable of performing their intended function during monthly surveillance testing; and, (ii) the corresponding B system instruments are unaffected and are capable of initiating the full logic for ECCS system operation assuming an undetected degradation and failure in the A channels.

This item remains open pending continued verification by the inspector that the instrumentation channels remain operable until problems caused by the beta shields are resolved, and final action by the licensee to restore the electrical independence and separation intended by the instrument design.

2.14 (Open) Follow Item 84-21-02: Operability of CRD 18-11. The reactor scrammed on Feburary 6, 1985 and all control rods inserted into the core, including rod 18-11. A special friction test was completed on rod 18-11 on February 7, 1984. No problems were noted in its operation and the testing verified that the rod was coupled with its drive.

One of two recorders used to monitor control rod insertion speeds during scrams malfunctioned during the transient on February 6, 1985, and no data was obtained for the rods. Single scrams for 38 rods were completed during the routine surveillance testing on March 2, 1985 to meet the Technical Specification 4.3.C.2 requirements that the insertion times for 50% of the rods in each quadrant be measured in 32 week intervals. No unacceptable conditions were identified.

As noted in Inspection Report 84-21, this item remains open pending completion of the licensee's evaluation and repair of CRD 18-11.

3.0 Observations of Physical Security

Selected aspects of plant physical security were reviewed during regular and backshift hours to verify that controls were in accordance with the security plan and approved procedures. This review included the following security measures: guard staffing; random observations of the secondary alarm station; verification of physical barrier integrity in the protected and vital areas; verification that isolation zones were maintained; and implementation of access controls, including identification, authorization, badging, escorting, personnel and vehicle searches. No inadequacies were identified.

4.0 Shift Logs and Operating Records

Shift logs and operating records were reviewed to determine the status of the plant and changes in operational conditions since the last log review, and to verify that: (1) selected Technical Specification limits were met; (2) log entries involving abnormal conditions provided sufficient detail to communicate equipment status, correction, and restoration; (3) operating logs and surveillance sheets were properly completed and log book reviews were conducted by the staff; (4) potential reportable occurrences were filed as licensee event reports when required; and, (5) Operating and Special Orders did not conflict with Technical Specification requirements.

The following plant logs and operating records were reviewed periodically during the period of February 5 - March 4, 1985:

Shift Supervisor's Log
Night Order Book Entries
Control Point Log
Valve Lineup File
Jumper/Lifted Lead Log
Maintenance Request Log
Switching Order Log
Shift Turnover Checklists
RE Log Typer-Core Performance Log
Potential Report Forms

+ PRO 2/85 dated 1/7/85, Collet Housing Scratches
+ PRO 3/85 dated 1/7/85, 'B' Fuel Oil Transfer Pump Inoperable
+ PRO 5/85 dated 1/16/85, 'A' SLC Pump Seal Leaks
+ PRO 6/85 dated 1/24/85, 'B' Fuel Transfer Pump Motor Bearings
+ PRO 7/85 dated 1/25/85, Unapproved Change in SJAE Trip Setpoints

No unacceptable conditions were identified.

5.0 Inspection Tours

Plant tours were conducted routinely during the inspection period to observe activities in progress and verify compliance with regulatory and administrative requirements. Tours of accessible plant areas included the Control Room Building,

Reactor Building, Diesel Rooms, Control Point Areas, the Intake Structure and the grounds within the Protected Area. Control room staffing was reviewed for conformance with the requirements of the Technical Specifications and AP 0036, Shift Staffing. Inspection reviews and findings completed during the tours were as described below.

5.1 Systems and equipment in all areas toured were observed for the existence of fluid leaks and abnormal piping vibrations. Pipe restraints and snubbers installed on various piping systems were observed for proper fluid levels and condition. No inadequacies were identified.

5.2 Plant housekeeping conditions, including general cleanliness and storage of materials to prevent fire hazards were observed in all areas toured for conformance with AP 0042, Plant Fire Prevention, and AP 6024, Plant Housekeeping. The inspector had no further comment in this area, and no inadequacies were identified except as noted in section 11 below.

5.3 Tagging and control of equipment returned to service in accordance with Switching and Tagging Order 84-1369 was reviewed. No discrepancies were noted.

5.4 The inspector monitored the feedwater sparger leakage detection system data and reviewed the monthly summary of feedwater sparger performance provided by the licensee in accordance with his commitment to NRC:NRR made in letter FVY 82-105. The licensee reported that, based on the leakage monitoring data reduced as of January, 1985, there were (1) no deviations in excess of 0.10 from the steady state value of normalized thermocouple readings; and (2) no failures in the 16 thermocouples initially installed on the 4 feedwater nozzles. No unacceptable conditions were identified.

5.5 The status of the Residual Heat Removal, Residual Heat Removal Service Water, Service Water, High Pressure Coolant Injection, Core Spray, Standby Liquid Control, Fire Water Suppression and Reactor Core Isolation Cooling (RCIC) systems was reviewed to verify that the systems were properly aligned and fully operational in the standby mode. The review included the following: (1) verification that each accessible, major flow path valve was correctly positioned; (2) verification that power supplies and electrical breakers were properly aligned for active components; and, (3) visual inspection of major components for leakage, proper lubrication, cooling water supply, and general condition. No inadequacies were identified.

5.6 Radiation controls established by the licensee, including radiological surveys, condition of access control barriers, and postings within the radiation controlled area were observed for conformance with the requirements of 10 CFR 20 and AP 0503. No inadequacies were identified.

5.7 Implementation of jumper and listed lead (J/LL) requests 85-04 through 85-12 and mechanical bypass request (MBR) 85-01 was reviewed to verify that controls established by AP 0020 were met and no conflicts with the Technical Specifications were created. The inspector verified that installation and/or removal of selected requests was proper and in accordance with the established controls. No unacceptable conditions were identified.

5.8 Analysis results from samples of process liquids and gases were reviewed periodically during the inspection to verify conformance with regulatory requirements. The results of isotopic analyses of radwaste, reactor coolant, off-gas and stack samples recorded in shift logs and the Plant Daily Status Report were reviewed. No inadequacies were identified.

6.0 Operational Status Reviews

The operational status of standby emergency systems and equipment aligned to support routine plant operation was confirmed by direct review of control room instrumentation. Control room panels and operating logs were reviewed for indications of operational problems. Licensed personnel were interviewed regarding existing plant conditions, facility configuration and knowledge of recent changes to the plant and procedures, as applicable. Acknowledged alarms were reviewed with licensed personnel as to cause and corrective actions being taken, where applicable. Anomalous conditions were reviewed further.

Operational status reviews were performed to verify conformance with Technical Specification limiting conditions for operation and approved procedures. The following items were noted during inspector reviews of plant operational status.

6.1 On February 6, 1985 at about 5:00 P.M., the inspector noted that the volume on a stero radio in the control room was turned up for a few minutes for a financial news report. The radio was clearly audible in the front portion of the control room and was turned down after the news report. The plant had tripped four hours earlier and was in hot standby. The licensee stated that the crew on watch in the control room at the time of the incident would be instructed on the proper use of the radio. No problems were noted with the use of the control room radio throughout the remainder of the inspection period. No violations were identified.

6.2 The licensee declared a medical emergency at 1:05 P.M. on February 6, 1985 when a woman visitor became ill while on a tour of the plant. A Vermont State Representative felt 'faint' while on a tour of the refueling floor inside the Reactor Building. She was escorted outside the building and recovered after a few minutes. Site medical response personnel responded, but no offsite or special assistance was required. No inadequacies were identified.

6.3 During routine full power operations at 3:00 A.M. on February 11, 1985, the primary meteorological system computer became inoperable, which caused the loss of remote readout of meteorological data in the control room and at the offsite engineering offices. Local readout of meteorological data from the primary tower remained available from recorders in the relay house. Control room indications of wind speed and direction from the backup meteorological tower were also operable. However, at 8:00 A.M. on February 12, 1985, the backup indication of wind direction was lost in the control room.

Plant operators made a 50.72 notification to the HQ:DO at 8:00 A.M. regarding the loss of accident assessment information in the control room. There are no technical specification limiting conditions for operation for the meteorological

instrumentation. Instrument and Control personnel investigated the problems on both systems. The remote readouts from the primary met system were returned to service at 12:30 P.M. on February 12, 1985 following repair of the computer. The control room indication of wind direction from the backup system was returned to service by February 18, 1985 following repair of a tranducer at the tower.

No unacceptable conditions were identified.

6.4 During an Emergency Preparedness Table-Top Exercise interview with control room personnel at 5:00 P.M. on February 28, 1985, the inspector noted that control room TI-59 calculator used for dose projections during emergencies was not operable. Plan operators took actions to replace the unit. A replacement calculator was tested and returned to the control room by 10:15 A.M. on March 1, 1985. Spare calculators were available onsite for use during an emergency had that been necessary during the interim period.

Maintenance and use of the control room emergency response equipment will be examined on future NRC inspections and during the Emergency Preparedness Exercise scheduled for April 17, 1985. No other inadequacies were identified.

6.5 During a tour of the Reactor Building at 11:00 A.M. on February 12, 1985, the inspector observed that fire system deluge valve FP DV301 activated inadvertently during the performance of a routine surveillance test per OP 4020, Surveillance of Fire Protection Equipment, Revision 10, dated September 12, 1983. FP DV301 delivers fire water to the sprinkler systems in the Northwest corner of the Reactor Building to protect equipment on the 252 and 232 foot elevations. The sprinkler systems cover both banks of cable trays carrying indication and control cables for ECCS Division I and II equipment as they pass into the Reactor Building from the Cable Vault. No cables were sprayed with water since the fusible links on the sprinkler headers had not opened.

Operation of the deluge valve caused a minor leak of water through a controlled leakoff valve on FP DV301, which wetted the floor on both the 232 and 213 foot elevations in the RCIC quadrant. Activation of the deluge valve also caused both fire water pumps to automatically start on low header pressure. The deluge valve operation and the fire pump start were alarmed in the control room. An auxiliary operator responded immediately to the alarm, verified that the activation was inadvertent, and isolated the sprinkler header by closing unstream isolation valve FP 322. This action secured the leakage to the RCIC quadrant. No equipment was jeopardized by the leakage. Operators took actions to reset the deluge valve, but subsequently experienced trouble clearing an alarm circuit associated with the valve. Since the problems were not resolved by 3:30 P.M., the shift supervisor declared the Cable Penetration Sprinkler system inoperable and instituted a fire watch for the area in accordance with Technical Specification 3.13.F.2. An hourly fire patrol was maintained on the area until 7:06 P.M. on February 13, 1985 when the sprinkler system was returned to an operable status.

The cable penetration area sprinkler system is a dry header preaction system that is activated by ionization fire detectors located on both the 252 and 232 foot

elevations of the RCIC quadrant. The preaction system was originally installed to operate on detectors located on the 252 foot elevation only. As a result of his commitments to the NRC staff in FVY 84-53 dated May 26, 1984, the licensee modified the cable penetration sprinkler system under PDCR 84-03 to expand the areas covered by the sprinkler headers, and to include detectors on the 232 foot elevation of the RCIC quadrant in the sprinkler initiation circuit. FP DV301 activated during testing of the detectors on the 232 foot elevation. The version of OP 4020 in use for the test did not require that the deluge valve isolation valve, FP 322, be closed as a precaution during detector testing. Further testing under OP 4020 was suspended pending completion of a temporary change (DI 85-01) to incorporate requirements that reflected the changes made per PDCR 84-03.

The inspector met with the Fire Protection Coordinator and the plant Cognizant Engineer for PDCR 84-03. PDCR 84-03 modifications for the Northwest sprinkler system were completed on January 18, 1985 and the system was turned over to the Operations Department and declared operable at 1:10 P.M. The sprinkler system was operable based on satisfactory completion of the PDCR 84-03 installation procedure. However, three procedures affected by the design change were not issued concurrent with system turnover. OP 2186, Fire Suppression System was revised by DI 85-06, which was issued on February 13, 1985. The changes to OP 2186 included the addition of fire system valves associated with a new DV301 installed during the design change. OP 2190, Service Air System, was issued on January 29, 1985 but not distributed to the control room for implementation. Three valve lineup changes instituted by the DI were completed prior to system turnover. A change to OP 4020 was in progress when the system was turned over in January, 1985. Plant operators should not have accepted the system turnover from construction without revised, approved operating procedures in place.

The inspector discussed his concerns regarding implementation of PDCR 84-03 with the Technical Services Superintendent during a meeting on February 15, 1985. The licensee stated that concerns in this area had been previously identified by the Vermont Yankee staff and INPO. The Engineering Support Department had noted that the turnover package for installation and test procedures had some steps out of order, and the procedure needed to be revised to assure procedures were issued when the system was declared operable. The licensee intends to revise the administrative requirements to assure that all procedures (including surveillance) be issued prior to system turnover to operations. One of the findings from the December, 1984 INPO assessment of the facility was that modified systems were sometimes turned over to operations before critical drawings and procedures were available to operators. The licensee's resolution of this issue will be followed on subsequent NRC inspections.

AP 6000, Plant Design Change Requests, Revision 9, requires in Appendix A Step 9.b that procedures required for operation of modified systems be revised and issued prior to initial system operation. AP 6000 also requires that surveillance procedures be revised and reissued within 30 days after installation of the PDCR, or prior to the next scheduled use of such procedures, whichever is earlier. The cognizant engineer for PDCR 84-03 identified the operating and surveillance procedures that required revision and the departments responsible for the procedures

were notified. The implementing departments failed to assure that the procedures were issued at the time of system turnover. In the case of OP 4020, there appears to be no mechanism in the licensee's procedures that will assure revised surveillance procedures are issued prior to the next scheduled use of the procedures following installation of the PDCR. The failure to issue operating and surveillance procedures for PDCR 84-03 in accordance with the requirements of AP 6000 is contrary to the requirements of Technical Specification 6.5.A (VIO 85-08-01).

7.0 The following surveillance tests were reviewed to verify that testing was performed by qualified personnel; test data demonstrated conformance with Technical Specification requirements; and, system restoration to service was proper.

+ OP 4337, Reactor Water Level ECCS Functional Test, 2/12/85
+ OP 4340, Reactor Low Pressure ECCS Valve Permissive, 2/22/85
+ OP 4020, Surveillance of Fire Protection Equipment, 2/12/85
+ OP 4123, Core Spray System Valve Testing, 2/20/85
+ OP 4349, Core Spray A/B Logic Test, 2/6/85
+ OP 4376, Torus-Reactor Building Vacuum Breaker Testing, 2/19/85

No inadequacies were identified.

8.0 Maintenance activities were reviewed todetermine the scope and nature of work done on safety related equipment. The review included consideration of the following: the repair of safety related equipment received priority attention; Technical Specification limiting conditions for operation (LCOs) were met while components were out of service; performance of alternate safety related systems were not impaired; the requirements of AP 0021 were met; and, equipment return to service was proper, including the completion of operability testing.

+ MR 85-223, CRP 9-48 Indication of Wind Direction
+ MR 85-256, Relay CS14A-K11B Deenergized During OP 4349
+ MR 85-306, Meteorological Data Readout in the Control Room
+ MR 85-330, Diesel Generator A Jacket Cooling Water Leaks
+ MR 85-226, Vacuum Breaker Pressure Switch Cable Replacement
+ MR 85-267, Core Spray Flow Switch Cable Replacement

No inadequacies were identified.

9.0 Review of Plant Trips and Events

The inspector reviewed events that occurred during the inspection to verify continued safe operation of the reactor in accordance with the Technical Specifications and regulatory requirements. The following items, as applicable, were considered during the inspector's review of operational events:

-- observations of plant parameters and systems important to safety to confirm operation within approved operational limits;

-- description of event, including cause, systems involved, safety significance, facility status and status of engineered safety feature systems;

-- details relating to personnel injury, release of radioactive material and exposure to radioactive material, as applicable;

-- verification of correct operation of automatic equipment, based on a review of the plant computer post-trip logs, as applicable;

-- verification of proper manual actions by plant personnel and verification of adherence to approved plant procedures; and,

-- verification that notifications were made to the NRC and offsite agencies in accordance with 10 CFR 50.72, as applicable.

9.1 The reactor shutdown automatically from full power at 11:04 A.M. on February 5, 1985 when a 'MCA Generator Trip' signal was inadvertently generated during a routine surveillance test. Testing of the core spray system 'B' actuation logic was in progress in accordance with OP 4349. The main generator trip signal is developed within the core spray system actuation logic to trip the generator in the event of a loss of coolant accident. The reactor protection system sensed the generator load rejection and tripped the reactor. Both diesel generators started as a result of the spurious actuation signal, but were not required to power the 4KV buses since plant loads were automatically transferred to the startup transformers.

A PCIS Group 1 isolation occurred on high steam flow when the reactor operator placed the mode switch in the 'startup' position with main steam line flow greater than 40%. The isolation was reset to restore the main condenser as the reactor heat sink. The A and C reactor feedwater pumps were operating prior to the transient and both pumps tripped on high vessel water level following the scram. The C pump was restarted for vessel level control. The A feedwater pump began to "windmill" when its discharge check valve failed to close following pump shutdown. The pump motor outboard bearing overheated and smoked due to insufficient lubrication, which caused a fire alarm to occur in the main control room at 11:35 A.M. There was no open fire. Plant operators shut the pump discharge isolation valve. No other safeguard systems were called upon to actuate. Plant operators stabilized the plant by 11:25 A.M. in accordance with the reactor scram recovery procedure.

The licensee reviewed the core spray logic test sequence and determined that test switch 14A-S14B malfunctioned to allow the normally blocked MCA generator trip and diesel start signals to pass while the low-low vessel level logic condition was present. Switch 14B is in series with test blocking relay 14A-K24B which will energize when a multi-function test switch is installed in test jack J1B to perform the logic test. Auxiliary 'b' contacts on relay 24B are in series with relays K11B and K12B and normally block the MCA and diesel start signals. During the testing on February 6, 1985, switch 14B developed momentary high contact resistance for a sufficient period of time to allow relay K24B to deenergize. The contact faces on the switch were pitted and gave resistance readings that varied from open to short circuit with the switch closed. The test switch was replaced along with pins I and J on jack J1B. The blocking circuit was verified to work properly. The core spray logic test was later completed satisfactorily.

During subsequent operation of the B feedwater pump, operators noted excessive seal packing leakage and the pump was secured for maintenance. Plant restart was commenced following completion of startup prerequisites at 2:06 A.M. on February 7, 1985. The licensee restarted the plant with the C feedwater pump, which would allow power operation up to 50% full power. The B pump was returned to service after the seal leakage was repaired. The plant returned to full power operation at 2:00 P.M. on February 9, 1985.

Damage to the motor and pump bearings on the A feedwater was extensive and the pump was left out-of-service pending replacement of the bearings and rework of the bearing journals. The auxiliary oil pump started as required at 7 psi pressure on the header. The shaft driven lube oil pump also ran backwards with the feedwater pump. However, the combination of flow from both pumps was insufficient to lubricate the bearings as the pump ran backwards during parallel operation with the C pump. The discharge check valve for the A pump was disassembled and found to be cocked on its seat due to excessive play in the disc pivot arm. The valve was repaired.

The licensee completed a review of the trip prior to plant restart and concluded that power operation could safely resume. The inspector reviewed Post Trip Report 85-1 dated February 6, 1985 and the transient sequence of events. No inadequacies were identified.

10.0 Plant Piping Analyses

10.1 Scram Discharge Volume Piping

In a letter dated June 6, 1983, the licensee reported that the scram discharge volumes, new instrument volumes, instrumentation, and associated piping and valves were seismically qualified following upgrades to resolve concerns raised by the scram failure at Browns Ferry in 1980. The licensee reported further by letter dated February 28, 1984 that the results of additional analyses of the scram system determined that the hydraulic control unit (HCU) supports required additional modifications to bring their frequency response in line with the original analysis assumptions and FSAR criteria for structural integrity. The HCU support modifications would be completed by the end of 1984.

By letter FVY 85-12 dated February 1, 1985, the licensee reported that the HCU modifications were completed. However, during the integrated closeout review of the design change, the licensee determined that additional supports for the scram insert and withdraw lines are necessary. The present schedule calls for completing the required design work by July of 1985 and making any required modifications during operation, if possible or no later than the end of the 1985 outage.

Based on the analysis contained in NUREG 0803 and evaluations which verified the NUREG's applicability to VY, the licensee determined that operation of the plant is justified pending completion of additional modifications to the insert and withdrawal line pipe supports. The licensee's position was based on the fact that the potential consequences of leakage from the scram discharge system were

thoroughly analyzed in NUREG 0803 and found not to be a matter of safety concern. The licensee's evaluation for this item was previously reviewed and accepted by the staff, as documented in Region I Inspection Reports 82-18 and 83-02.

The inspector had no further comment on the licensee's planned actions at this time. However, this item is considered unresolved pending further staff review of: (i) nature of deficiencies and scope of modifications required on the scram insert/withdraw lines; and, (ii) the licensee's ability to complete an integrated analysis of the scram system to resolve the seismicity issue in a timely manner (UNR 85-08-02).

10.2 Seismic Upgrade Program

Licensee actions in response to IE Bulletin 79-02 began by testing concrete anchor bolts on supports designated seismic by the original architect engineer. This led to the replacement of all existing Philips self-drilling anchors on these supports with Hilti-Kwik bolts early in 1980 and provided a partial resolution of the bulletin. An interim resolution to address the flexibility effects on base plate and anchor bolt design stresses was made by demonstrating that a factor of safety of at least two existed. The Bulletin 79-14 effort was started in late 1979. Discrepancies between the Ebasco piping model and the field conditions were evaluated and resolved within the context of the original design methodologies. This work was completed in the Spring of 1980, and the licensee reported that the bulletin requirements were completely resolved at that time.

Since there were differences in the modeling and analysis methodologies used in the original design and current-day practice, the licensee decided to upgrade design calculations in parallel with the evaluation of base plate flexibility undertaken to address Bulletin 79-02. The Seismic Reanalysis Program was outlined in a letter dated July 25, 1980 and has been underway since then. The licensee's plans and schedules for completing the program and base plate flexibility evaluations were reviewed (reference Inspection Report 81-15) and found acceptable. The licensee informed the staff of the status of the reanalysis program by letters FVY 83-16 dated March 1, 1983 and FVY 84-67 dated June 27, 1984.

As part of the reanalysis effort, the original seismic design was reviewed and upgraded to current regulatory requirements. The original maximum hypothetical earthquake (SSE) zero period acceleration of 0.14 was retained; however, the ground response spectrum was revised to conform with Regulatory Guide 1.60. SSE floor response specta were generated in conformance with Regulatory Guide 1.61 and 1.122, using new building models which were verified against as-built data. The approximations obtained from the original static methods using the so-called Robinson Fix were no longer employed. Additional details on the seismic reanalysis program were provided by the licensee in the references cited above. In general, the licensee has demonstrated that completion of the seismic reanalysis program using modern analysis methods will resolve the Bulletin 79-02 concerns and provide an enhanced design basis for the seismicity of safety-related piping.

The inspector reviewed activities in progress during the inspection period related to the seismic reanalysis program. EDCR 84-402, Seismic Piping

Reanalysis, has been issued to the site for implementation. The scope of the EDCR is to address all Bulletin 79-02 concerns to ensure that all seismic supports with concrete expansion anchor bolts will have a mimimum factor of safety of 4 (four), when baseplate flexibility is taken into consideration. The minimum factor of safety is between the bolt design load and the bolt ultimate capacity determined from static load tests conducted for the anchor bolt manufacturers.

Bulletin 79-02 concerns will be resolved by modification, addition, and/or deletion of pipe supports as detailed in Enclosure D of the EDCR. Piping inside the drywell was excluded because it does not utilize concrete expansion anchors. Also excluded from the scope of EDCR 84-402 were all piping and supports addressed under EDCR 82-35 (Torus Attached Piping Supports), EDCR 83-21 (RRU 5-8, RRU 9, RRU 17 A and B, and UPS Service Water Supports), EDCR 83-23 (Additional Torus Attached Piping Supports), and EDCR 83-05 (Inaccessible Pipe Supports), which also addressed concerns of IE Bulletin 79-02. The licensee reported during inspection that there are 700 additional modifications (some very minor) and 83 additional seismic supports needed to complete the upgrade. Work activities under EDCR 84-402 will be reviewed during subsequent routine inspections.

The scope of the engineering effort and modifications exceeded the licensee's initial expectations and the licensee began to look for alternatives to reduce the number of required modifications. The licensee implemented Special Test Procedure (STP) 85-01, Procedure for Small Bore Pipe Supports, during the inspection period to ascertain through testing the ability of small bore pipe supports to withstand the design loads. Predetermined loads at specified directions were supplied to 14 supports. Successful completion of the load test verified that the support hardware, structural components, baseplates, and bolts needed no further modification. The inspector reviewed STP 85-01 and noted that the scope of testing was limited to small bore piping 2.5 inches or less in diameter. The licensee performed a safety evaluation for the proposed testing and established procedural controls to assure the load tests would not adversely affect the operability of systems tested, or create an unreviewed safety question. The licensee's engineering organization specified the loads to be applied to each support and identified these supports for which additional restraints were used to do the tests. All 14 supports tested passed the load test.

The licensee is considering an additional test program for small bore piping. The inspector requested the licensee to identify: (i) how a representative sample will be picked to determine the scope of small bore piping to be tested; and, (ii) what confidence level will be achieved to assure that the sample adequately represents the population of supports. YNSD engineering is using a statistical program for testing concrete expansion anchors to define the sample size. This effort was still in progress at the conclusion of the inspection. This item will be followed on a subsequent routine inspection (IFI 85-08-03).

11.0 Fire Water System Operability Reviews

11.1 Fire System Status and Surveillance Testing

The inspector verified that the vital fire suppression water system was operable by: (i) verifying that major flow path valves listed in procedure OP 2186

matched as built drawing; (ii) walking down portions of the system located in the intake structure, plant yard, reactor building, and turbine building, and, (iii) reviewing 1984 and 1985 surveillances, including:

-- 4020.01, Weekly fire battery check
-- 4020.02, Monthly operation check of the fire pumps
-- 4020.10, Quarterly fire battery check
-- 4020.16, Annual fire protection system operation performance and capacity check
-- 4020.18, Annual valve cycling and flush of the loop yard
-- 4020.03, Monthly inspection of key valves
-- 4020.21, Operating cycle fire battery checks.

The findings from this review were as described below.

11.1.1 The data sheet for the quarterly fire battery checks, OP 4020.10, for a test on September 25, 1984 could not be located at the time of the inspection. An informal maintenance schedule for that time period indicated that the test had been completed and no problems were identified. This appeared to be an isolated records problem.

11.1.2 The annual valve surveillance completed per OP 4020.18 on July 12, 1984 had a major Reactor Building header flow path valve, FP 302, mislabeled as FP 342, a minor vent valve on the recirc MG foam system. A note on the data sheet for the surveillance indicated that valve 342 rather than valve 302 was cycled during the test. Failure to test valve FP 342 was contrary to the requirements of Technical Specification 4.13.B.1.d to cycle each testable flow path valve at least once per 12 months (VIO 85-08-04).

Valve FP 302 was cycled during Switching and Tagging Order 84-1369 on December 5, 1984, thereby demonstrating its operability during maintenance on the fire suppression system. The licensee stated that valve FP 302 had been cycled annually until July 27, 1983, when a typographical error was made in procedure OP 4020.18 while incorporating changes for revision 10, issued in September, 1983. The inspector noted that revision 11 for OP 4020, which was in routing for review and approval, still listed valve FP 342 rather than FP 302. The Fire Protection Coordinator noted this finding to correct the item.

The inspector discussed these problems with the Plant Manager during the inspection. The inspector expressed his concern that procedural performance problems and errors were not identified and corrected during the review process. The licensee noted the inspector's comments.

11.1.3 During a tour of the switchgear room on February 26, 1985, the inspector noted that the two fire doors separating the East and West switchgear rooms would not shut completely due to an out-of-adjustment automatic closure mechanism. The inspector noted further that neither door was posted as a fire door that must be kept closed. These findings were discussed with the Fire Protection Coordinator, who issued maintenance request MR 85-403 to adjust the fire doors and paint signs.

The inspector noted on March 4, 1985 that the fire doors were adjusted to close properly. This item remains open pending completion of licensee actions to post the switchgear room doors as fire doors and subsequent review by the NRC (IFI 85-08-05).

11.2 Status of Modifications to Meet Appendix R Requirements

The licensee responded to NRC inspection findings in Region I Inspection Report 83-26 by letters FVY 84-53 dated May 23, 1984 and FVY 84-149 dated December 28, 1984. The responses identified the plant modifications that would be completed to correct certain deficiencies in meeting the fire protection requirements of 10 CFR 50, Appendix R. The status of actions on these items were reviewed during the inspection, as summarized below. The 'item numbers' below refer to those used in letter FVY 84-53.

11.2.1 Item 1 - Reactor Building Northwest Corner Room, 232 foot
Install a pre-action water suppression system to cover the corner room using the existing detectors to activate the system.

Status - Complete. Work was completed during the inspection to install the system per PDCR 84-03.

11.2.2 Item 4 - Reactor Building Northwest Corner, 252 foot
Install a pre-action water suppression system to cover the floor area to the steam tunnel wall and add a second level above the overhead cable trays.

Status - Complete. Work was completed during the inspection to install the system per PDCR 84-03.

11.2.3 Item 5 - Reactor Building Northwest Corner, 252 foot
Separate Control Cables for HPCI and RCIC Containment Isolation Valves.

Status - Complete.

11.2.4 Item 7 - Reactor Building Northeast Corner, 252 foot
Install a radiant heat shield between MCC 89A and MCC 89B and seal conduits running between MCC 89B and MCC 9D.

Status - Complete. Actions were completed to install shields in accordance with PDCR 84-05.

11.2.5 Item 8 - Turbine Building to Radwaste Building Personnel Corridor
Wrap power cables in the overhead area of the corridor with one-hour rated material.

Status - Complete.

Licensee actions to correct the deficiencies and complete other actions identified in FVY 84-53 will be examined further on subsequent NRC inspections.

11.3 Safe Shutdown Capability Analysis

The licensee provided for NRC staff review a draft copy of a Safe Shutdown Capability Analysis dated November 26, 1984 that was completed to satisfy the requirements of Section III.G of Appendix R. The report was the licensee's revised analysis for the Reactor Building that incorporated the NRC staff's requirements for a random loss of offsite power, and definition of fire areas. The analysis results indicated that certain conditions within the plant do not meet the requirements. The discrepancies will be resolved by modification, procedure revision and/or exemption request. Interim compensatory measures were instituted until the discrepancies could be resolved. The following discrepancies were identified by the analysis:

(i) Separation zones need to be established for circuits in the Reactor Building 280 foot, 213 foot and torus catwalk areas;

(ii) Discrepancies associated with diesel generator support circuits in the Turbine Building Loading Bay area, 252 foot elevation; and

(iii) Discrepancies associated with ECCS corner room and diesel generator fan cooler circuits in the main control room and HVAC corridor.

Compensatory measures were established in a memorandum from the Fire Protection Coordinator dated January 16, 1985, which consisted of the use of fire watch patrols in the areas noted above. The inspector reviewed the Fire Watch data sheets for all three shifts for the period from January 22 to February 19, 1985 and noted that the data sheets had been revised to incorporate the requirements of the January 16 memo and were complete. The fire watches tour each designated area at least 4 times per shift to review the status of conditions and ongoing work activities. No inadequacies were identified.

The inspector had no further comment on this item at the present time. Licensee actions to correct deficiencies will be examined as part of the NRC staff followup to the concerns raised in inspection report item 83-26-01.

12.0 Review of Licensee Event Reports (LERs)

Licensee event reports 84-11, Revision 1 was reviewed in the NRC Resident and Regional Offices. The report was reviewed to verify that the event and its safety significance were clearly described; the cause of the event was identified and corrective actions taken (or planned) were appropriate; and, the report satisfied the requirements of 10 CFR 50.73. The inspector noted that the update report provided additional information regarding the cause of the Type C leak rate test failures for each component and the actions required to repair the valves. The inspector had no further comment in this area.

No inadequacies were identified.

13.0 Management Meetings

Preliminary inspection findings were discussed with licensee management periodically during the inspection. A summary of findings for the report period was also discussed at the conclusion of the inspection and prior to report issuance.