U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 85-02

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: January 2 - February 4, 1985

Inspectors: William J Raymond 2/15/85
W. J. Raymond, Senior Resident Inspector date

Approved by: J. E. Tripp 2/22/85
J. E. Tripp, Chief, Reactor Projects date
Section 3A, Projects Branch 3

Inspection Summary: Inspection Conducted January 2 - February 4, 1985

Areas Inspected: Routine, unannounced inspection on day time and backshifts by the resident inspector of: actions on previous inspection findings; plant power operations, including operating activities and records; plant physical security; surveillance testing; maintenance activities; licensee event reports followup; IE Circular and Information Notice followup; compensatory measures for fire protection requirements; control room and housekeeping assessments and, conformance of staffing requirements with 10 CFR 50.54(m). The inspection involved 108 inspection hours.

Results: No violations were identified in 11 areas inspected. A concern was identified regarding the conformance of control room staffing criteria in administrative procedure AP 0036 with the requirements in 10 CFR 50.54(m) - see paragraph 13. Three licensee identified violations were not cited in that they met the criteria of 10 CFR 2, Appendix C.IV.A (Paragraphs 6.5, 7, and 9.3).

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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 personnel listed below.

Mr. G. LeClair, Assistant Operations Supervisor
Mr. D. Reid, Operations Superintendent
Mr. J. Pelletier, Plant Manager

2. Status of Previous Inspection Findings

2.1 (Closed) Follow Item 84-26-01: Reporting Requirements for Inoperable Fire Equipment. The licensee informed the inspector on January 17, 1985 that, since the sprinkler system on the Reactor Building 252 foot elevation was inoperable for scheduled design modifications, then the degraded mode was exempted from special reporting requirements by Technical Specification 6.7.C.2, Amendment 43. The inspector reviewed Amendment 43 and concurred with the licensee's assessment. This item was opened based on a review of Technical Specification 6.7.C.2, Amendment 83, which becomes effective on April 1, 1985 and contains no exemption from reporting requirements based on design changes. The licensee stated that the reporting exemptions were inadvertently deleted from the specification during the preparation of Amendment 83 and actions would be taken to correct the omission. This item is closed.

2.2 (Closed) Follow Item 84-26-03: Schedule for Completion of Fire Protection System Modifications. The licensee reported his schedule for completing fire protection system modifications by letter FVY 84-149 dated December 28, 1984. The licensee stated that due to installation difficulties and material delivery problems, the work originally scheduled for completion by the end of 1984 would be done by February 8, 1985. The schedule addressed modifications identified as items 1, 4, 7, and 8 in the licensee's May 21, 1984 letter (FVY 84-53). The inspector noted during this inspection that modification activities associated with the above items appeared to be complete as of February 4, 1985. This item is closed.

2.3 (Open) Follow Item 84-18-03: Technical Specifications for Containment Vacuum Breakers. The inspector reviewed a draft copy of a proposed change to Technical Specification 3.7.5.b that the licensee intends to submit to the staff in March, 1985. The licensee proposed to change the specification to require the following:

> "From and after the date that one of the pressure suppression chamber - reactor building vacuum breaker systems is made or found inoperable for any reason, reactor operation is permissible only during the succeeding seven (7) days, unless such vacuum breaker is sooner made operable, provided that the repair procedure does not violate containment integrity and the requirements of specification of 3.7.D.2 is met".

The inspector noted that the proposed specification would not address the concerns discussed in Inspection Report 84-18, nor would it preserve containment integrity for the penetration in a manner consistent with the standard technical specifications. An essential element missing from the licensee's proposed specification is a requirement that would assure and preserve the containment isolation function for the penetration without sole reliance on a swing check valve. Additionally, the proposed specification would apparently not disallow unlimited operation with a vacuum breaker failed in the open position. The inspector's comments were discussed with licensee personnel. This item remains open pending subsequent NRC review of the licensee's proposed change to Technical Specification 3.7.5.b.

2.4 (Closed) Violation 84-21-11: Uncontrolled Licensed Material in the North 40 Storage Area. The licensee responded to this item by letter FVY 85-02 dated January 14, 1985. The material was removed to the radiation controlled area for temporary storage pending proper disposal. Detailed surveys of the North 40 area were conducted to identify and remove other licensed material, as discussed in Inspection Report 84-21. The licensee's investigation concluded that the material was placed in the North 40 area prior to January, 1984. Plant procedures and controls were revised during 1984 to establish more stringent monitoring requirements for licensed material. The licensee further concluded that the violation occurred as a result of past practices that have since been improved. Previous NRC staff review of this area (reference Inspection Reports 84-21, 84-24 and 84-17) concluded that the licensee's improved administrative controls should be sufficient to preclude recurrence of a violation of this type. This item is closed.

2.5 (Closed) Violations 84-21-12 and 84-21-13: Failure to Survey and Control Licensed Material. The licensee responded to these items by letter FVY 85-02 dated January 14, 1985. The corrective actions taken in response to Item 84-21-11, as described above, should prevent recurrence of the violations. Additionally, the licensee stated that prior to any future storage of licensed material in the owner controlled area, plant procedures and facilities will be reviewed and revised as necessary to assure that the requirements of 10 CFR 20.207 are met. These items are closed.

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, 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; and, (4) 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 January 1 - February 4, 1985:

-- Shift Supervisor's Log
-- Night Order Book
-- Control Point Log
-- Valve Lineup File
-- Jumper/Lifted Lead Log
-- Maintenance Request Log
-- Switching Order Log
-- Shift Turnover Checklists
-- Radiochemistry Analysis Log
-- Core Performance Typer-Log
-- Potential Report Forms
dated January 7, 1985 and January 25, 1985

4.1 PRO 2/85 was written on January 7, 1985 concerning possible cracks that were identified on control rod drive #7012 during inspections completed in September, 1984. The results from a routine liquid penetrant examination completed on September 4, 1984, while rebuilding the drive revealed crack indications on the collet housing. The indications were parallel with the axis of the collet housing, and were faint and shallow. The indications were further evaluated through a second liquid penetrant test and the licensee concluded that the indications were most likely scratches which occurred during previous installation and removal of the drive. Liquid penetrant examination results were recorded on forms VYAPF 0203.02 dated September 4, 1984 and OQA-X-1.1 dated September 12, 1984.

Control rod drive #7012 uses the relatively new 7000 series tube design. The possible crack indications were of particular interest due to intergrannular stress corrosion cracking (IGSCC) that has been observed at other facilities. The indications observed at VY were not circumferential and were not in the area of concern on the collet housing for IGSCC cracking. The licensee's final dispositioning of this item is open pending confirmation of the licensee's evaluation by the General Electric Company. The drive is not in service now and will not be returned to service until after satisfactory completion of the evaluation. The licensee determined that this item was not reportable.

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, Turbine Building, Reactor Building, Diesel Rooms, Radwaste Building, 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 0C36, 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 hangers and restraints installed on various piping systems were observed for proper installation 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. Work controls were reviewed for conformance with the fire permits established for work in progress in the reactor building on the 252 foot elevation. Work activities to upgrade the cable penetration area sprinkler system under PDCR 84-03 were completed on January 18, 1985. The inspector verified on January 21, 1985 that fire water system valves 323, 322, 302, 340 and 341 were open to return the sprinkler system for the Northwest corner of the reactor building to service following completion of the modifications. No inadequacies were identified.

5.3 Tagging and controls of equipment released from service were reviewed during the inspection tours to verify equipment was controlled in accordance with AP 0140, VY Local Control Switching Rule. Controls implemented per Switching and Tagging Orders 85-29, 85-36 and 85-60 were reviewed, and 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 December 31, 1984, 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 (RHR), RHR Service Water, Standby Gas Treatment System, High Pressure Coolant Injection, Core Spray, Standby Liquid Control 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. Radiation work permits (RWPs) were reviewed to verify conformance with procedure AP 0502. Work activities in progress were reviewed for conformance with the requirements of RWPs 84-3101, 84-3113, 85-6, 85-89 and 85-97. No inadequacies were identified.

5.7 Implementation of the following jumper (J/LL) requests was reviewed to verify that controls established by AP 0020 were met; no conflicts with the Technical Specifications were created; requests were properly approved prior to installation; and, installation and removal was in accordance with the requests: J/LL requests 84-187 and 85-1 through 85-3. 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. Sample results for the standby liquid control tank on January 1, 1985 showed that the boron concentration was maintained within technical specification limits. No inadequacies were identified.

5.9 System valve lineups established to maintain containment integrity and isolation capability were reviewed on a sampling basis during inspection tours to verify conformance with the configuration specified by OP 2115, Revision 13. The review confirmed that manual valves were shut, capped and locked as required by procedure; power was available to motor operated valves and no physical obstructions would block operations; and, no leakage was evident from valves, penetrations and flanges. No inadequacies were identified.

6.0 <u>Operational Status Reviews</u>

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 Plant operators found one of two channels of drywell pressure recorder 16-19-44 downscale and inoperable at 4:30 P.M. on January 4, 1985 and the channel was declared inoperable. Post accident drywell pressure indication was thus not available and a 7-day action statement was entered per Technical Specification 3.2.G. Instrument technicians replaced a blown fuse in the power supply circuit, and the channel was returned to an operable status at 6:10 P.M. on January 4, 1985. The recorder operated satisfactorily until 10:25 A.M. on January 7, 1985 when the pressure channel again failed downscale. Subsequent investigation by Instrument & Control personnel on January 9, 1985 determined that the GE isolated power supply was faulty and the unit was replaced. The post-accident pressure recorder operated satisfactorily for the remainder of the inspection period. No inadequacies were identified.

6.2 During routine operations at 100% full power on January 12, 1985, plant operators noted a 5% to 7% decreasing oscillation on average power range monitors (APRM) A and D. Both APRM channels were bypassed at 8:50 P.M. Technical Specification 3.1.1 requires that at least 2 APRM channels be operable per RPS trip system and this condition was satisfied with channels C and E, and B and F. Subsequent investigation of individual local power range monitors (LPRM) determined that detector 4C-32-17 was indicating low. LPRM 4C-32-17 is common to APRM channels A and D, and both channels returned to proper levels when LPRM 4C-32-17 was bypassed at 9:05 P.M.

The detector power supply was replaced as a preventive maintenance measure, but the power supply was not the cause for the observed problems. LPRM 4C-32-17 was returned to service at 12:25 A.M. on January 13, 1985 and the A and D APRM channels showed normal indications. Subsequent licensee review could not identify a problem with the LPRM. The neutron detector channels operated satisfactorily during the remainder of the inspection period. The performance of the power range detectors will be reviewed during subsequent routine inspections. No inadequacies were identified.

6.3 The A RHRSW pump was started on January 16, 1985 for the torus cooling mode following routine HPCI and RCIC testing. The A RHRSW pump was shutdown at 2:50 A.M. when the auxiliary operator noted an unusual noise apparently coming from the pump. Plant operators considered the pump to be operable and no alternate surveillance testing was initiated. The pump was later operated for maintenance personnel, who determined that the noise did not originate from the pump. The A RHRSW pump was released for service at 9:50 A.M. on January 16, 1985. No inadequacies were identified.

6.4 The inspector reviewed the status of freeze protection panels at the facility and the actions taken by licensee personnel to maintain and conduct surveillance on the panels to assure that systems important to safety were protected from freezing during cold weather. Heat tracing and space heating circuits were energized and no problems attributed to cold weather were noted on lines susceptible to freezing. The service water to cooling tower supply valve, SW-11, was open to keep the alternate cooling supply from freezing.

Several minor discrepancies with heat tracing circuits were noted by the inspector during tours on January 16-18, 1985, which were discussed with Operations and Maintenance personnel for followup. Heat tracing circuit 9 on panel 1F and circuit 18 on panel 1D appeared to have faults and required repair. The service water lines protected by these circuits were reviewed and the inspector determined that the lines were adequately protected by either backup space heating, other heat tracing circuits, and/or the presence of hot process water that normally flows through the lines. Items noted by the inspector had already been identified by the licensee and maintenance requests were issued.

One minor discrepancy was noted on freeze protection panel 1H which had heat tracing circuits 15 and 18 tagged open by switching and tagging order 77-73 dated August 26, 1977. The heat tracing circuits were originally installed on instrument lines for the condensate storage tank, which were removed by subsequent modifications. The heat trace circuits were thus not needed for freeze protection. The current control room tagging logs had no record of switching and tagging order 77-73. The finding was discussed with the supervisory control room operator who noted the item for followup of the open tagging order. Failure to properly track and/or close tagging order 77-73 is contrary to the administrative requirements in AP 0140. However, the tagging order is so old that it would be inappropriate to cite this item and solicit corrective actions at this time given the probability that there is little connection between the activities in 1977 and current tagging practices and controls. Concerns regarding recent tagging practices have been identified by the NRC and improvements in tagging controls are being followed by Inspection Item 84-18-01.

No other inadequacies were identified.

6.5 Plant operators noted spikes in the steam jet air ejector (SJAE) radiation monitors (OG-150 A&B) on four occasions during the period - January 17, 22, 23, and 25. For each occurrence, indicated radiation level returned to normal within a few minutes and there were no other indicators of abnormal radiation levels from other process monitors. The operators concluded that the spikes occurred as a result of flow perturbations in the monitor sample lines caused by hydrogen detonations in the offgas system upstream of the recombiners. Plant operators and Chemistry & Health Physics (C&HP) personnel reviewed offgas system operations and could not identify any recent operational changes that would explain the periodic events.

On January 25, 1985, C&HP personnel reduced flow to the radiation monitors from 20 to 10 cubic feet per hour in an attempt to reduce or eliminate a potential cause of the detonations. This action lowered the normal readings on the radiation monitors from 20 to 10 mR/hr. Plant operators recognized this action at 11:30 A.M. as an unreviewed change to the monitor calibration with a possible non-conservative impact on the isolation trip setpoints prescribed for the channels by Technical Specification 3.2.D and 4.8.C.1.f - "...offgas monitors shall be calibrated to measure radioactivity released with a high setpoint equivalent to 0.3 Ci/sec after a 30 minute decay". The operators requested C&HP personnel to return the offgas flow rate to 20 cfh and a potential reportable occurrence report was submitted for management review.

Licensee calculations showed that the equivalent trip setpoints were 0.026 and 0.06 Ci/sec for flows of 20 and 10 cfh, respectively. Thus, the setpoints were set low enough with respect to the limit of 0.3 Ci/sec, that an offgas system isolation would have occurred prior to violation of the technical specification value. The item was not reportable based on the above.

The licensee determined that the event occurred due to a combination of personnel and procedural deficiencies in that OP 4511 should have been used to evaluate the change in setpoints prior to making the sample flow changes. Recommendations were made to the responsible supervisors to follow up on the item to effect corrective actions. Failure to follow the requirements of OP 4511 on January 25, 1985 was contrary to the requirements of Technical Specification 6.5 that was identified and corrected by the licensee. No Notice of Violation will be issued since this event meets the criteria in 10 CFR 2, Appendix C.IV.A.

The inspector identified no inadequacies during his review of the event. Offgas system operation and performance will be reviewed during subsequent routine inspections.

7.0 Review of Licensee Event Reports

Licensee event report (LER) 84-24 dated January 9, 1985 was reviewed in the NRC Resident and Regional offices. The event concerned the failure to perform a functional test of the HPCI-torus water level system as required by Technical Specification Table 4.2.1 during the week of October 1, 1984. The test was missed due to an oversight by the I&C Engineer when he failed to include OP 4375 along with OP 5374 in the weekly surveillance schedule. The LER 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. No Notice of Violation will be issued since the event meets the criteria in 10 CFR 2, Appendix C.IV.

No inadequacies were identified.

8.0 IE Circular and Information Notice Review

Licensee responses and actions taken for the IE Circulars and Information Notice listed below were reviewed to verify that: (i) the materials were received onsite, reviewed for applicability to the facility; and, (ii) corrective actions taken, or planned, were appropriate. Licensee actions on the following circulars and notice were reviewed:

8.1 IE Circular 81-03: Inoperable Seismic Monitoring Instrumentation. This item was previously addressed in Inspection Report 82-01. Subsequent licensee reviews of the onsite seismic instrumentation was documented in internal memos dated September 21, 1982 and November 22, 1982. The plant surveillance procedure was reviewed in light of the concerns identified in the circular and no procedural changes were found necessary. The licensee further reviewed his seismic instrumentation against the requirements in the FSAR, License DPR-28 and 10 CFR Part 100, and concluded that the existing instrumentation meets all applicable commitments. No inadequacies were identified. This item is closed.

8.2 IE Circular 81-05: Self Aligning Rod End Bushings for Pipe Supports. The results of the licensee's review of suppressors and supports in the plant with spherical rod bushings was documented in a memo dated July 7, 1983. None of the problems described in the circular were noted. Additionally, changes were made to Yankee Atomic inservice inspection procedure VA-VT-11 to incorporate inspection criteria to review for the type of problems identified in the circular. No inadequacies were identified. This item is closed.

8.3 IE Circular 81-06: Potential Deficiencies Affecting Foxboro Transmitters. The licensee's review of this item, documented in a memo dated June 24, 1982, determined that Foxboro transmitters are not used in safety related applications at the plant. The circular information will be kept in a technical information file for future consideration. This item is closed.

8.4 IE Circular 81-09: Containment Effluent Water that Bypasses Radioactivity Monitors. Licensee review of this item was documented in a memo dated February 4, 1982. A review of applicable drawings for the service water system by Operations and C&HP personnel determined that there are no pathways from containment where service water can bypass radiation monitors installed to monitor the effluents. This item is closed.

8.5 IE Circular 81-11: Inadequate Decay Heat Removal During Reactor Shutdown. The results of the licensee's reviews were documented in a memo dated August 11, 1981. Changes were made to OP 2124, Residual Heat Removal System, to incorporate precautions and requirements that would preclude the occurrence of the conditions described in the circular. No inadequacies were identified. This item is closed.

8.6 IE Circular 81-12: Inadequate Periodic Test Procedures of PWR Protection Systems. The equipment and conditions described in this circular were not applicable to the Vermont Yankee plant. This item is closed.

8.7 IE Information Notice 84-86 dated November 30, 1984: Isolation Between Signals of the Protection System and Non-Safety Related Equipment. This notice was received onsite and routed by the Assessment Coordinator to the I&C Supervisor for review in early January, 1985. No further review had been completed as of this inspection. The I&C Supervisor stated that further reviews would be required to determine whether concerns addressed in the notice are applicable to the facility. No inadequacies were identified. This item will be followed on a subsequent inspection to determine the result of the licensee's review (IFI 85-02-01).

9.0 Surveillance Activities

The inspector reviewed portions of the following surveillance tests to verify that testing was performed by qualified personnel; test data demonstrated conformance with Technical Specification requirements; test data anomalies were appropriately resolved; surveillance schedules were met; test results were reviewed and approved by supervisory personnel; and, system restoration to service was proper.

+ OPF 4121.05, RCIC Pump Operability and Full Flow Surveillance, 1/16/85
+ OPF 4120.01, HPCI Pump Operability and Full Flow Surveillance, 1/16/85
+ OPF 4115.04, Drywell-Suppression Chamber Vacuum Breaker and Indication Operability Test, 1/16/85
+ OPF 4114.01, Standby Liquid Control Pump Capacity Test, 1/16/85
+ OPF 4403.01, Backup Core Limits Evaluation, 1/30/85
+ OPF 4401.01, Core Thermal Limits Evaluation, 1/31/85
+ OPF 4340.02, Reactor Low Pressure ECCS Valve Permissive Calibration, 1/23/85 and 1/25/85
+ OPF 4124.06, RHR Service Water System Surveillance, 1/24/85
+ OPF 4181.01, Service Water System Surveillance, 1/24/85
+ OPF 4182.01, Reactor Building Cooling Water Surveillance, 1/22/85

9.1 The inspector reviewed the inservice test results for three pumps that have been classified in the "alert" range for performance trending. The 1C Service Water and the 1D RHR Service Water pump vibration levels were recorded in the range of 4.9 to 6.9 mils during the monthly functional test. The 1D RHRSW pump entered the alert range in November, 1984. The pump vibrations normally run at less than 4.9 mils. The licensee increased the testing frequency on the pumps to biweekly to better monitor performance and identify adverse trends. Other monthly functional test parameters on both pumps are satisfactory and the pumps are considered fully operational. Operation in the alert range can continue indefinitely.

The A RBCCW pump was classified in the alert range based on pump differential pressure measured at 77.5 psi during the December, 1984 and January, 1985 tests. The normal range for this parameter is 65.7-76.25 psi. Other functional parameters on the pump are acceptable. The licensee took the pump out of the alert classification after further evaluation of performance data. The licensee determined that the increased pump differential pressure was due to the reduced cooling flow through plant equipment and heat exchangers, which has been throttled back because of the cold service water temperatures. The increased pump delta-P is an expected condition during winter operations.

No inadequacies were identified. The functional testing and performance of the station cooling water pumps will be followed on subsequent routine inspections.

9.2 The licensee completed a calibration of ECCS vessel pressure channels PT 2-3-52C and 52D in accordance with OP 4340 on January 23, 1985. The pressure channels provide an open permissive for low pressure core cooling system valves following an accident. Technical Specification Table 3.2.1 requires that the trip setting (permissive) be within 300 to 350 psig for LPCI valves, and greater than 300 psig for CS valves. OP 4340 verifies a trip setting of about 315 psig, with a reset on the trip setting at about 325 psig.

During testing on January 23, 1985, and subsequent troubleshooting on January 25, 1985, the licensee noted that the PT-52D trip and reset functions operated correctly at the appropriate setpoints, but signal spikes occurred on the reset indication from the master trip unit during the attempts to verify the reset differential setting was proper. The signal spikes on PT-52D were accompanied by 'noise' spikes on two other electrically separate instrumentation channels, LR 2-3-67 and LT 2-3-73B. Level recorder LR-67 provides reactor vessel post-accident wide range level indication on CRP 9-3, and its output signal spiked downscale about 4 inches coincident with the reset function of PT-52D. Level transmitter LT-73B provides a permissive to divert LPCI flow to the containment cooling mode of operation when vessel water level is at 2/3 core height. The noise on LT-73B occurred on the "trip status LED" portion of the master trip unit circuitry; there was no noise noted on the LT-73B trip output signal.

Pressure transmitter PT-52D was declared inoperable for about 1 hour on January 25, 1985 to allow investigation under MR 85-158. The problem still existed after the 52D master trip unit card was replaced. However, the 315 psig trip setpoint for the channel was repeatedly verified by performance of the functional test in accordance with OP 4340. Testing of LT-73B and its associated trip circuitry confirmed that the channel functioned properly, but the 'noise' signals appeared in the opposite direction, i.e., on PT-52D. The down spike on the LT-67 indication occurred during the reset of either LT-73B or PT-52D. PT-52D and LT-73B are physically located on instrument panel ECCS CP-25-6B in the Reactor Building. Level transmitter LT-67 is located on instrument rack 25-5 in the Reactor Building. Both LT-73B and LT-67 provide level indication on CRP 9-3.

The licensee concluded that all instrument channels were capable of performing their intended protection and indication functions, and were therefore, operable. The satisfactory completion of monthly functional tests will provide continued verification of this operability and will detect any degradation in the channel performance. No anomalous conditions were observed on any of the channels other than when PT-52D and LT-73B were reset following a trip. The licensee postulated that the observed 'spiking' is caused by the high energy inductive kick that occurs when the relays associated with either unit de-energize. They believe that the energy is following either a high resistance path that exists between the bistable outputs of the master trip units for PT-52D and LT-73B, or is following the common side of the 24 VDC power supply that powers the channels in CP-25-6B. The fact that no spurious channel output relay trips have occurred suggests that the latter path is the most probable.

The down spiking of LT-67 was attributed to a ground loop that exists on the cable that carries the indication loop currents for both LT-73B and PT-67. The signals from these channels share a common junction box as they pass from the Reactor

Building to the cable vault. The ground loop is possible since the shields for LT-67 are grounded in the control room, and the shields for LT-73B are grounded in the Reactor Building.

The licensee has postulated that a high resistance path between the signal wires of LT-73B and PT-52D could have been created during the installation of beta-shields in the instrument cabinets during the 1984 refueling outage in accordance with EDCR 84-411. The beta-shields are metal plates constructed around the instruments to reduce the beta dose to the electronics following an accident, and were added to provide environmental qualification for the instrumentation. The shields created a small gap between the electronics and the sides of the cabinet through which the channel wire bundles pass. It is possible that the wires were pinched during the installation of the shield. The licensee has deferred further investigation of the problem due to the sensitivity of the instrumentation involved and the possibility of causing a plant transient.

The inspector reviewed the licensee's actions and evaluation of the instrumentation channels. No inadequacies were identified. The schedule for performing functional testing of LT-73B and PT-52D to assure continued operability was discussed with the I&C Supervisor. It was noted that the tests (OP 4340 and OP 4337) were conducted on a staggared schedule which will allow more frequent verification that channel conditions have not deteriorated through a degradation of the high resistance path. A discrepancy in the past performance of OP 4340 was identified by the licensee and is discussed further below.

The inspector had no further comment on this item for the present. This item is considered unresolved pending (i) further reviews by the inspector to verify the instrumentation channels remain operable as required by the Technical Specifications; and (ii) further action by the licensee to restore and/or otherwise assure the electrical independence and separation of the instrument channels intended by the design (UNR 85-02-02).

9.3 During the review of the 1985 surveillance schedule, the licensee noted that OP 4340 was last performed on July 30, 1984 to calibrate the instruments used to provide low pressure open permissive for both LPCI and CS system valves. Technical Specification 4.2.1 requires that the LPCI low pressure #3 trip function be calibrated every three months, and OP 4340 should have been performed by November, 1984 to satisfy that schedule.

The original design used pressure switches in channels PT-52C and PT-52D, and the Technical Specification 4.2.1 surveillance frequency was once per three months for both the LPCI and CS pressure permissives. Pressure transmitters were installed in place of switches in a design change completed during the 1984 outage. Consistent with past practice and operating experience, the surveillance frequency for the analog channels was increased to once per operating cycle, and a change to the Core Spray section of Table 4.2.1 was processed. The LPCI section of the table for low pressure #3 was overlooked during the technical specification revision.

The licensee will perform OP 4340 every three months to meet the LPCI test requirements until the specification is changed. The licensee determined that this item is reportable under 10 CFR 50.73 and a written report will be submitted to the NRC. The LER for this event will be reviewed by the inspector on a subsequent routine inspection.

Failure to test the LPCI low pressure #3 trip function in November, 1984 was contrary to the requirements of Technical Specification Table 4.2.1. The violation was identified and corrected by the licensee. No Notice of Violation will be issued since the event meets the criteria in 10 CFR 2, Appendix C.IV.A.

10.0 Maintenance Activities

The maintenance request log was reviewed to determine the scope and nature of work done on safety related equipment. The review confirmed: the repair of safety related equipment received priority attention; Technical Specification limiting conditions for operation (LCOs) were met while components were out of service; and, performance of alternate safety related systems was not impaired.

Maintenance activity associated with the following was reviewed to verify (where applicable) procedure compliance and equipment return to service, including operability testing.

+ MR 84-2260, Standby Liquid Control Pump Piston Gland Leakage
+ MR 84-2351, Offgas Monitor RAN-OG-3128 Detector Replacement
+ MR 85-20, Drywell Pressure Recorder 16-19-44 Inoperable
+ MR 85-42, B Diesel Generator Fuel Oil Pump Manual Switch
+ MR 85-45, Drywell Pressure Recorder 16-19-44 Inoperable
+ MR 85-77, LPRM 4C-32-17 Drifting Downscale
+ MR 85-134, B Diesel Generator Fuel Oil Pump Bearings
+ MR 85-158, Reactor Vessel Pressure PT-52D Reset Differential

10.1 Plant operators declared the B Diesel Generator inoperable at 8:35 A.M. on January 24, 1985 to perform maintenance on the fuel oil transfer pump. Alternate surveillance testing was commenced in accordance with Technical Specifications 3.5.H.1 and 4.10.A.1.a. The pump motor bearings were replaced and the pump to motor alignment was verified. Surveillance testing on the B diesel was completed satisfactorily at 2:15 P.M. and the diesel was declared operable at 3:25 P.M. on January 24, 1985. Alternate system testing was secured.

The inspector reviewed the maintenance work package and noted that safety grade bearings were not used as replacements. The use of non-Q bearings was reviewed by the licensee prior to installation. Commercial grade bearings were found equivalent and acceptable based on an engineering evaluation contained in the maintenance package. The licensee's Quality Assurance plan, YOQAP-1-A, Appendix C, Section V.2, allows the use of commercial grade components for small spare parts that have no traceability, provided an engineering evaluation concluded the non-Q part is otherwise equivalent. The licensee plans to conduct a followup evaluation of the bearing after a 100 hour operational run as part of the final acceptance of the non-Q component.

No inadequacies were identified.

11.0 Fire Protection Compensatory Measures

The licensee completed a Safe Shutdown Capability Analysis for the Reactor Building in accordance with the requirements of Section III.G of 10 CFR 50, Appendix R. The analysis results were summarized in a Yankee Atomic report dated November 26, 1984, which was submitted to the NRC staff for review. The staff is scheduled to meet with the licensee to review his analysis results in February, 1985. The analysis results showed that certain locations within the plant do not meet the requirements of the rule. The discrepancies will be resolved either by plant modifications, revised procedures, or exemption requests. The discrepancies and their resolutions will be reviewed by the staff during the forthcoming meeting.

The licensee extended the established fire watch patrols to cover the deficient areas as a compensatory measure pending final resolution of each discrepancy. The extended fire watch controls were implemented through a memo from the Fire Protection Coordinator dated January 16, 1985. The memo identified the areas to be reviewed by the fire watch at least 4 times per shift; specified the duties of the fire watch during the patrols; and, identified the locations of extra portable fire extinguishers that will be provided in the Reactor Building until the discrepancies are resolved. The following areas were found deficient during the analysis and were covered during the fire watch patrols:

+ general areas of the 280 foot elevation of the Reactor Building pending the establishment of a separation zone;

+ establish separation zones on the 252 foot elevation of the Reactor Building for the cable penetrations and MCCs 89A, 89B and 9D;

+ establish separation zones in the torus 213 foot elevation and the catwalk in the Reactor Building for the DC power feeds to RCIC and torus temperature and level cables;

+ provide protection for diesel generator support equipment and RRU circuits that pass through the Turbine Building 252 foot elevation - condemin area, and through the Turbine Building loading bay area; and,

+ provide protection for heating and ventilation circuits for the diesel room, Reactor Building corner room, and the main control room.

The inspector verified that compensatory measures were implemented in accordance with the January 16, 1985 memo. No discrepancies were identified. The adequacy of the licensee plans and actions to resolve the identified discrepancies will be reviewed during the forthcoming meeting with the NRR and Region I staffs.

12.0 Housekeeping and Control Room Assessment

The inspector completed an assessment of established administrative controls regarding plant housekeeping and control room protocol. The assessment was completed in accordance with guidelines provided by NRC Region I management and the assessment results were provided to NRC Region I for further review and consideration. The analysis results were discussed in a meeting with the Plant Manager on January 11, 1985, and areas of strengths and weaknesses as defined by the guidelines were noted.

One item of particular interest where VY policy deviated from the staff guidelines concerned the use of a radio in the control room at the discretion of the shift supervisor. The informal policy allows use of the radio so long as it is played at a low enough volume to not cause a distraction during the performance of routine duties. The inspector noted during past observations that the radio is generally used in a manner that does not cause a distraction. However, the sound level from the radio has been excessive on a few occasions. The inspector informed the licensee that this item will be reviewed during future routine inspections to verify that the radio is used in a manner that conforms with the established policy and that maintains a good working environment in the control room.

13.0 10 CFR 50.54(m) Staffing Requirements

The inspector reviewed the staffing requirements in procedure AP 0036, Shift Staffing, Revision 4, against the criteria specified in 10 CFR 50.54(m), inclusive of the Statement of Consideration for the rule. The VY staffing requirements meet the following requirements of the rule:

+ the minimum staffing plan includes two personnel with senior operator licenses and two with reactor operator licenses; a shift supervisor with a SRO license is required on site;

+ the procedure requires that a licensed senior operator be in the control room at all times other than cold shutdown conditions;

+ the procedure requires that a licensed reactor operator or senior operator be within a designated 'line of sight' area with the main control panels (i.e., "at the controls") at all times.

The administrative policies in AP 0036 appear to allow a situation contrary to the intent of 10 CFR 50.54(m) wherein one senior operator and one reactor operator are in the control room, and the senior operator is the designated "operator at the controls", while the reactor operator is elsewhere within the control room. The statement of consideration for the rule indicates that the senior operator should not be in a position where he has to manipulate the controls and perform the required immediate manual actions following an accident or transient, since doing so will detract from his primary duty of maintaining an overview of the plant response. The inspector has noted on occasions in the past that, with the shift supervisor onsite but away from the control room, the duty senior operator was momentarily "at the controls" while the reactor operator was elsewhere in the control room.

The inspector reviewed the control room and noted that an operator stationed anywhere within the control room proper or the adjacent office spaces can hear the control room annunciators and/or otherwise maintain voice communications with the operator "at the controls". The inspector further noted that the transit time from anywhere within the control room proper to the "controls" area was less than 30 seconds.

The inspector requested that the licensee review AP 0036 in light of the statement of consideration for the staffing requirements in 10 CFR 50.54(m) to determine whether the administrative controls should be revised to better meet the requirements of the rule. This item is considered unresolved pending completion of the licensee's review and further staff review of this item (UNR 85-02-03).

14.0 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.