U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 85-18

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: May 7 - June 3, 1985

Inspectors: William J Raymond 7/8/85
W. J. Raymond, Senior Resident Inspector date

Approved by: J. E. Tripp 7/16/85
W. E. Tripp, Chief, Reactor Projects date
Section 3A, Projects Branch 3

Inspection Summary: Inspection on May 7 - June 3, 1985 (Report No. 50-271/85-18)

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; followup of potential diesel generator problems; review of operator readiness to implement the new OEs; followup of peer inspection program status; followup of corrective actions for the receipt inspection program; and review of equipment qualification issues. The inspection involved 113 inspection hours.

Results: No violations were identified in 8 areas inspected. Operational status reviews identified no conditions adverse to safe operation of the facility. Further licensee evaluation of operator readiness to implement the new emergency procedures appears warranted (section 8). Further licensee action is required to assure the onsite inspection program meets the YOQAP requirements (section 9.1). Further NRC staff review is required to determine whether previous licensee actions were adequate to correct a violation regarding the inspection of maintenance activities (section 9.2).

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DETAILS

1. Persons Contacted

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

Mr. P. Donnelly, Acting Technical Services Superintendent
Mr. S. Jefferson, Assistant to the Plant Manager
Mr. D. Reid, Operations Superintendent
Mr. J. Pelletier, Plant Manager

2. Status of Previous Inspection Findings

2.1 (Closed) Follow Item 85-14-01: Failure to Complete a Safety Evaluation for J/LL 84-53. This item was reviewed with the Engineering Support Supervisor on May 28, 1985. The individual who completed jumper request 84-53 also worked on J/LL 85-19 and was thus aware that a safety evaluation should have been prepared for the changes made to pump P91-1A when the former request was completed in 1984. The inspector stated that counseling the individual regarding the AP 0020 requirements to complete a safety evaluation for those jumpers that change the facility as described in the FSAR constituted an acceptable corrective action for the item. The inspector stated that this item constituted a licensee identified violation of the requirements of AP 0020 and Technical Specification 6.5. The item will not be cited since it meets the criteria contained in 10 CFR 2, Appendix C.

2.2 (Open) Unresolved Item 85-10-06: Peer Inspection Program Status. Licensee actions to review the peer inspection program continued during the inspection. A Task Force was created to evaluate the process and provide recommendations for improvements to plant management by June 6, 1985. The deficiencies identified by OQA in Audit No. 85-11 were reviewed during this inspection and are described in paragraph 9 below. This item remains unresolved pending further NRC review of the deficiencies identified by the licensee, the proposed resolutions, and the implementation schedule for corrective actions.

2.3 (Open) Unresolved Item 85-10-04: Licensee Assessment of Operator Readiness to Implement New Emergency Procedures. The inspector interviewed licensee management to determine the results of the licensee's assessment regarding implementation of the new symptom orientated emergency operating procedures (EOPs) by June 1, 1985. Assessments completed by the Training Manager and the Operations Superintendent concluded that the operators were ready to implement the new EOPs even though there might be some "uneasiness" about using them on the part of some operators, due to the fact that the procedures dealt with plant damage states far in excess of design basis events.

The inspector interviewed a sampling of operators regarding their confidence level in using the procedures. The operator interviews were conducted as a followup of the NRC staff's concern raised during reviews of this area in March, 1985, and because of an anonymous call made to the NRC Region I Office on May 28, 1985 by a

Vermont Yankee operator, who expressed concerns regarding the adequacy of the training and readiness to implement the procedures. The results of the operator interviews, described in section 10 below, indicated that additional training should be provided to the operators prior to implementing the procedures.

After discussions with NRC Region I and NRR personnel on May 30, 1985, the licensee delayed implementation of the procedures pending further interviews with the operators and pending the completion of training to correct any deficiencies identified during the interviews. This item is discussed further in section 8 below.

Licensee actions to evaluate operator readiness to implement the new symptom based emergency operating procedures will be reviewed further on a subsequent inspection.

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; verification of physical barrier integrity in the protected and vital areas; random tours of the central and secondary alarm stations; verification that isolation zones were maintained; and implementation of access controls, including identification, authorization, badging, escorting, personnel and vehicle searches. No inadequacies were identified.

3.1 The Operations Superintendent notified the inspector at 10:40 A.M. on May 8, 1985, that plant management had halted a FSV-1 cask shipment (see section 5.3 below) after determining that the driver for the carrier arrived at the site with alcoholic beverages in his possession. The driver was disallowed from taking the shipment and the motor carrier company was contacted to supply a new driver, after assurances were received that applicable transportation policies and regulations would be observed. The following was determined during the inspector's followup of the incident.

The driver arrived at the site at about 8:00 A.M. and was processed at Gate 2 prior to entry into the site. In response to routine inquiries from plant security personnel, the driver stated that he had some beer in the truck, which was confiscated by security personnel. The officer who processed the driver also thought he noticed the smell of alcohol, but was not sure. Security personnel processed the driver into the plant under escort and continued to observe his behavior. The driver moved his vehicle into the reactor building and hooked up to the cask trailer prior to the halt of the operation by plant management. No abnormal behavior was noted by security personnel. (The NRC inspector had previously observed the trailer hook up operation and noted neither aberrant behavior nor the smell of alcohol from the driver). The driver was escorted to the plant offices for further interviews.

The driver was interviewed by licensee personnel, representatives from the State of Vermont and members of the Vermont State Police force, who were on site by previous arrangement to escort the shipment after it left the plant. The State Police administered a breath analyzer test to the driver at 11:00 A.M. and found that he was sober and could legally drive. The driver was allowed to disengage his rig from the waste shipment and leave the site.

The response of plant security to this incident was subsequently discussed with the Plant Manager. At the time of discovery of the alcohol at 8:00 A.M. on May 8, 1985, the guards responded properly by confiscating the beverage and maintaining the individual under cognizance pending further evaluation of his behavior. The guards apparently were not aware at the time of the provisions of 49 CFR 392.5, which prohibits the driver of an interstate carrier from possessing alcoholic beverages while operating on public roadways.

The inspector stated that the licensee is ultimately responsible for assuring compliance with all applicable regulations governing a waste shipment. While the licensee cannot reasonably be expected to assume responsibility for the actions of a carrier away from the plant site, he can act on evidence that may indicate the carrier's intent to comply with the rules. The inspector stated that, given a similar situation in the future, the possession of alcoholic beverages by a carrier who arrives to pick up a waste shipment should constitute sufficient grounds for plant security personnel to disallow the carrier from entering the site to take possession of the shipment.

The plant policy and instructions to security personnel on this issue will be followed by the inspector on a subsequent inspection (Follow Item 85-18-01).

4.0 Shift Logs and Operating Records

Shift logs and operating records were reviewed periodically 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; (4) log book reviews were conducted by the staff; (5) potential reportable occurrences were filed as licensee event reports when required; and, (6) Operating and Special Orders did not conflict with Technical Specification requirements.

No unacceptable conditions were identified.

5.0 Inspection Tours

Plant tours were conducted during the inspection period to observe activities in progress and verify compliance with administrative requirements. Systems and equipment in areas toured were observed for fluid leaks and abnormal vibrations, and pipe snubbers and restraints were observed for proper conditions. Plant housekeeping conditions were observed for conformance with AP 0042, Plant Fire Prevention, and AP 6024, Plant Housekeeping. Inspection reviews and findings were as described below.

5.1 The inspector reviewed the feedwater sparger leakage detection system and the monthly performance summary provided by the licensee in accordance with letter FVY 82-105. The licensee reported that, based on the leakage monitoring data reduced as of April 30, 1985, there were no deviations in excess of 0.10 from the steady state value of normalized thermocouple readings, and no failures in the 16 thermocouples initially installed on the 4 feedwater nozzles. No unacceptable conditions were identified.

5.2 The status of the Residual Heat Removal, Residual Heat Removal Service Water, High Pressure Coolant Injection, Core Spray, 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: (1) verification that accessible, major flow path valves were correctly positioned; (2) verification that power supplies were properly aligned; and, (3) visual inspection of major components for leakage, proper lubrication, cooling water supply, and general condition. No inadequacies were identified.

5.3 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. Work activities were reviewed for conformance with the requirements of RWP 85-527. No inadequacies were identified.

The inspector reviewed licensee activities in progress on May 8, 1985, to prepare an FSV-1 cask containing spent control rods for shipment to the waste burial site. The inspector reviewed the cask radiation and contamination survey results with the HP technician who performed the work. Additionally, the inspector performed an independent radiation survey of the cask with licensee instrumentation to verify that the 49 CFR 173 dose limits were met at the surface of the cask and at 2 meters. No inadequacies were identified.

The inspector noted that QC coverage for the shipment was provided by the independent onsite OQA group. The inspector reviewed the detailed checklist used by the QC inspector and verified that it covered various aspects of the shipment, including checks for waste classification, isotopic composition, radiation surveys, shipment markings, vehicle placarding, and DOT requirements. No inadequacies were identified.

The inspector had no further comments regarding the licensee's preparation of the cask for shipment. The delivery of the shipment to a carrier for transport to the offsite burial ground is discussed further in section 3 above.

6.0 Operational Status Reviews

The operational status of emergency and power generation systems was confirmed by direct review of control room instrumentation. Control room panels and operating logs were reviewed for indications of operational problems. Control room staffing and protocol were reviewed to assure manning requirements were met and acceptable working conditions were maintained. Licensed personnel were interviewed regarding existing plant conditions 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 the technical specifications and approved procedures. Inspection findings were as described below.

6.1 The licensee performed a special surveillance on control rod 18-11 during a control rod pattern exchange on May 18, 1985. The surveillance consisted of obtaining TIP scans adjacent to the rod location while moving the rod to verify that the control rod was connected to and following the drive mechanism. The inspector reviewed the TIP traces taken with TIP machine #3 as the rod was moved from position 24 to 46. The change in axial flux shape confirmed that rod 18-11 was moving with its drive mechanism. No inadequacies were identified.

6.2 Both containment air monitors were removed from service during the inspection period to perform maintenance. The containment particulate monitor was taken offline for preventive maintenance at 8:20 A.M. on May 9, 1985 after technicians noted problems adjusting the monitor during a routine calibration. The containment gas monitor was taken offline at 5:20 A.M. on May 18, 1985 for corrective maintenance after failing downscale. The detector was replaced and the monitor was declared operable at 12:05 P.M. on May 22, 1985.

The loss of each monitor caused the plant to enter the Technical Specification 3.6.C.2 action statement, which permitted continued reactor operation without the monitors for up to 7 days. The inspector verified that the monitors were returned to service within the 7 day period, and that the primary coolant system leakage monitoring systems (drywell sumps) remained operable per the Technical Specification 3.6.C.2 LCO. No inadequacies were identified.

6.3 A trouble alarm occurred on the recirculation weld leakage detection system (moisture sensitive tape) at 3:00 A.M. on May 15, 1985. Plant operators investigated the alarm but could not identify its cause at the local control panel. There were no indications of weld or recirculation system leakage. A maintenance request was submitted for I&C technicians to investigate the problem, but the alarm subsequently cleared.

A trouble alarm occurred at 7:00 A.M. on May 17, 1985, and leakage status information was lost from 5 of the 6 detectors. There were no indications of increased leakage from the containment monitoring systems. I&C Personnel subsequently investigated the system electronics at the local control panel and identified no problems. Following shutdown of the system for a cooldown period, the system was returned to service by May 24, 1985.

No other problems occurred on the LDS for the remainder of the inspection period and status information from each of the detectors showed no leakage from the recirculation system welds.

The inspector reviewed licensee actions regarding the leakage detection system (LDS) for conformance with the administrative requirements in MOO Directive 84-02 dated August 2, 1984. The change in operability status was reported to the NRR Project Manager at 3:50 P.M. on May 17, 1985. No inadequacies were identified.

6.4 Plant operators identified leakage past the RCIC system discharge valves following routine RCIC surveillance testing on May 14, 1985. Leakage past the check valve, RCIC 22, has been a long standing problem that will be addressed in a plant design change during the refueling shutdown. The leakage on May 14, 1985 was noted based on pressurization of the RCIC suction piping to about 85 psig, which indicated that the normally closed injection valve, RCIC 21, failed to seat fully following testing. The design pressure limit for the schedule 40S stainless steel line is 150 psig. Pressure on the line was relieved and an entry into the steam tunnel was made to manually tighten down on RCIC 21. No other problems were experienced. No inadequacies were identified.

6.5 A ground developed on the negative leg of the B 125 volt station battery during the inspection period. The battery was considered fully operational since all parameters remained satisfactory and degradation would occur only if a second ground subsequently developed on the positive leg. Ground search operations were initiated in accordance with OP 2145 to locate and eliminate the cause of the problem. The source of the ground was not identified during the inspection period and no degradation in battery conditions occurred. Licensee efforts to locate and eliminate the ground will be followed during subsequent routine inspections.

During ground search activities at 1:45 P.M. on May 28, 1985, plant technicians discovered a burned coil in relay 16A-K16, which performs a seal-in function in the reset circuit for the power supply to the AC solenoids on the outboard MSIVs. The AC solenoids were de-energized due to the failure of the K16 relay, but the MSIVs were held open by the DC solenoids. The General Electric Series CR120 control relay was replaced. Based on a discussion with Assistant I&C Foreman, the inspector determined that there has not been an excessive failure history with CR120 relays installed at the plant.

The inspector reviewed the function of the relay as shown in Control Wiring Diagrams 1111 and 1119,and noted that the undetected failure of the relay could not prevent the MSIVs from performing the intended isolation function, but it would prevent resetting the logic following a trip. It is not known exactly when the relay failed. The relay most likely failed sometime after February 6, 1985, when the MSIV logic was reset following a PCIS Group 1 isolation. No inadequacies were identified.

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

The inspector noted that recent maintenance activities on the diesel generators (DG) included the replacement of the Nugent fuel oil filters (reference MR 85-737). A review of the maintenance history file for both generators showed that fuel filters were changed 12 times on the A DG, and 8 times on the B DG since 1971. Fuel filters on the A DG were changed 4 times in the March to May period in 1983.

The inspector noted that licensee procedure AP 0150 requires the filters to be replaced when filter differential pressure reaches 5 psi. A differential pressure for a newly installed filter would be about 3 psi. The DG vendor recommends that the filters be changed when delta-P reaches 10 psi.

The maintenance history was discussed with the Assistant Maintenance Foreman and no problems or abnormal trends were identified. No inadequacies were identified.

7.0 Followup of a Diesel Generator Part 21 Report

The inspector received notification from NRC Region I of a 10 CFR Part 21 report that was filed by the Louis Allis Company on May 21, 1985, which involved a problem that may apply to the Fairbank Morse diesel generators installed at Vermont Yankee. The problem concerned the failure of a diesel at another facility where a inter-pole shorting strap broke during an engine overspeed test. The strap failed due to fatigue stress cracking. The problem was discussed with licensee personnel on May 31, 1985 and a copy of the Part 21 report was provided to the licensee for review on June 3, 1985.

Subsequent investigation by the licensee determined that the Vermont Yankee generators were of a design similar to the unit that failed and included the use of an Amortisseur dampener with inter-pole connecting straps. Licensee actions to review the failure event and develope a corrective action plan were in progress at the conclusion of the inspection. This item is considered open pending completion of the licensee's evaluation and corrective actions, and subsequent review by the NRC (Unresolved Item 85-18-02).

8.0 Operator Interviews Regarding OEs

The inspector interviewed licensed operators from each operating shift during the period from May 24-31, 1985 to determine how the operators felt about the recently completed training on the operational emergency procedures (OEs), and whether the operators felt ready to implement the procedures on June 1, 1985. The interviews covered a sampling of personnel who would be responsible for the procedures, including reactor operators, senior reactor operators, shift engineers, and staff and supervisory personnel. Interviews were conducted with individuals and entire shifts - Crew D on May 28, 1985, Crew F on May 28, 1985, and Crew E on May 30, 1985. The Plant Manager participated in the interview of Crew F. The results of the interviews and some of the concerns raised by the operators are summarized below.

The new OEs are significantly different from the old style emergency operating procedures. The most notable differences are: the new OEs are symptom rather than event based; the new OEs are in a logic flow chart format rather than narrative; and, the OEs deal with events that go far beyond analyzed design basis accidents.

The operators completed four phases of training on the new procedures consisting of an initial classroom review, which provided for operator verification of the procedures; 3 days of practice with the flow charts on the Dresden simulator, which is not identical to the Vermont Yankee design - the bases for the procedures were covered during the simulator session; review of the procedure bases during

the one week requalification training period; and a two hour 'scenario' review session with an instructor while on a backshift. The inspector observed a scenario review session conducted by the Training Department with Crew F on May 30, 1985.

8.1 Interview Results

8.1.1 Twenty seven interviews were completed by May 31, 1985, or about 66% of the total interviews to be conducted. Sixteen individuals (or 39% of the total) clearly expressed a desire to have more training on the procedures prior to implementation. The remaining 11 individuals felt 'comfortable' enough with the procedures to use them, but also expressed a desire to have more training to increase their confidence level. Most operators interviewed felt they would not be proficient in the new OEs if they had to use them. Some operators felt that they would still use the old emergency procedures from memory.

8.1.2 All operators interviewed felt that the format of the procedures was an improvement over the old style and would enhance safety. The operators felt that the training they did receive was good, but there was not enough of it. Additional classroom review as well as more simulator time was desired, but simulator time was considered by all as the most useful. Problems noted regarding the simulator training already received was that three days was not enough, the OEs were still undergoing revision concurrent with the training, and some of the operators were learning the OE bases for the first time at the simulator. The operators did not have a personal copy of the procedures for private study, although copies were available in the training department.

Those operators who desired additional training prior to implementing the procedures felt more training on the procedure bases was required, as well as additional simulator practice on using the procedures for complicated scenarios where coordination between several branches of the flow charts and/or other procedures is necessary. Some operators felt that it would be beneficial to standardize the roles and the lines of communication that would be used for a crew to act as a team.

8.1.3 Operator reservations in using the new procedures also stemmed from the limited exposure they had on the Off-Normal (ON) and Operational Transient (OT) procedures, which would be issued with the OEs. Although the contents of the ONs and OTs were essentially the same as the old procedures (which the operators were trained on and had used for years); there was relatively little training on the ONs and OTs, most of the training was directed toward the new 'symptom' sections separate from the main body of the procedures; and, there was no established cross reference between the ONs, OTs, and OEs to aid in coordination between the procedures. Another problem noted by the operators was that OP 0109, Plant Recovery, was referenced by the OEs, but was not ready for implementation with the procedures.

8.1.4 Some operators had technical concerns and questions with the OEs that were not completely resolved to their satisfaction. The example most often cited was from OE 3104, Torus Temperature and Level Control, which required operator decisions and actions to be performed based on torus water level measured over a range of 10 to 30 feet. The torus level instrumentation has a high range limit of 20

feet and is not considered reliable greater than 17 feet. Other concerns were expressed regarding the availability of materials and the lack of familiarity with the actions required to complete the instructions listed in the appendices to the OEs that would be used to: install jumpers to inhibit ADS; manually vent the scram pilot air header to insert control rods; and, install mechanical by-passes to inject the SLC tank through the CRD system.

The inspector met with the Senior Operations Engineer on May 30, 1985 to discuss the technical problems associated with the OEs. The torus level instrumentation maximum upper range limit is 20 feet. The licensee is planning to extend the torus measurement range by a design change during the 1985-1986 outage. The interim resolution to the discrepancy between the procedure and the instrumentation was to revise OE 3104 to have the operators seek guidance from the Technical Support Center whenever a decision regarding torus level would be required.

The inspector used the OE appendices to 'walk through' the steps required to install jumpers to inhibit the ADS function, and to pull fuses to disable control rod power supplies. The actions could be performed as prescribed by the procedures. The bases for the actions in the OE appendices were documented in a 5/17 memorandum to the Shift Supervisors, which should have resolved the concerns raised regarding those instructions. Apparently, the memo had not been distributed to the intended recipients.

8.2 Deferral of OE Implementation

By letter August 22, 1984, the licensee committed to implement the new OEs by June 1, 1985. The commitment was confirmed in an NRC Order as amended by letter dated September 28, 1984. Based on a conference call between the licensee and NRC Regional and NRR personnel on May 30, 1985, the licensee agreed to defer implementation of the new procedures pending completion of detailed interviews with each operator to determine their readiness to use the procedures, and pending the completion of training to correct any deficiencies identified during the interviews. The new OEs will be implemented as soon as possible, consistent with the above, but in no case later than the startup from the 1985-86 outage. The licensee's plans were accepted by the NRC staff.

The operator interviews were in progress at the conclusion of the inspection. The interview results will be followed on a subsequent inspection and the licensee's evaluation of operator readiness to implement the OEs will be followed by Inspection Item 85-10-04. The licensee's actions to correct the discrepany between present torus level instrumentation and OP 3104 is considered open and will be reviewed further on a subsequent inspection (Unresolved Item 85-18-03).

9.0 Actions on Peer Inspection Program Deficiencies

9.1 Background and Review of Audit Results

Based on previous problems noted internally and on the recent NRC findings at the Yankee facility, plant management requested the OQA group to conduct an audit

of the onsite inspection program to verify compliance with the requirements of the Yankee Operational Quality Assurance Program, topical report YOQAP-I-A. An OQA audit in March, 1985 identified several weaknesses in the onsite peer inspection process, as documented in OQA Audit Report 85-11 dated April 5, 1985.

The audit found that the onsite Inspection and Test Program was programatically adequate and effectively implemented in the areas of test control, control of measurement and test equipment, the ISI program and the IST program. However, in the area of plant inspections, specifically inspection of maintenance and maintenance related activities, the audit found procedural inadequacies with the YOQAP, and procedure implementation problems. The cause of the problems was found to be a lack of adequate procedural guidance on the performance of inspections.

The audit reviewed maintenance activities completed subsequent to the revision of AP 0021 in November, 1984. The audit resulted in 4 observations and 6 deficiencies (possible violations of YOQAP requirements). One deficiency concerned the inspection and verification of operating activities by the Maintenance Department. One observation related to the control of measurement and test equipment by the I&C group. All remaining items concerned procedural inadequacies and implementation problems related to the inspection of maintenance activities. The deficiencies are summarized below.

Def 1: Contrary to YOQAP-I-A, Criterion X, Section B.2.a (X.B.2.a), written instructions and checklists were not provided for the inspection of corrective maintenance activities.

Def 2: Contrary to X.C.1.g, maintenance procedure AP 0021 does not provide for a pre-implementation review of maintenance documentation by personnel knowledgeable in QA to determine the need for independent inspection, to identify the inspection personnel, and to establish documentation requirements for the inspection results. This review of maintenance activities would be in addition to the independent, second level inspection and surveillance already performed by OQA.

Def 3: Contrary to X.C.1.a, personnel who performed inspections for MRs 84-2046, 2049, 2110, 2124, 2169, 2187, 2260 and 85-268, 269, 330 were not independent from the personnel who performed the activity inspected.

Def 4: Contrary to XVII.C.1.a, maintenance reports that were used as inspection records did not contain three of the 9 required documentation elements: acceptance and rejection criteria; identification or procedures, drawings, manuals and specifications used for inspection; and identification of test equipment used in the independent inspection, inclusive of accuracy requirements.

Based on a May 9, 1985 interview with the YAEC QA manager responsible for the audit, the inspector determined that the QA auditors did find that independent inspections were being performed, that procedures and drawings were in use by the inspectors, and acceptance criteria were employed. The finding was that documentation for the inspection activity was not adequate, which presents a compliance problem with the YOQAP in assuring quality of the work activity.

Def 5: Contrary to the requirements of AP 0021, the auditors noted 14 MRs where second line supervisor inspections of work activities were documented on form AP 0020.02, but not on the appropriate block of AP 0021.01 as well.

Def 6: Contrary to X.C.1, for inspections conducted in July, 1984 per OP 1201, Reactor Vessel Assembly, the lead plant mechanic who performed the work also signed for having inspected the activity.

The plant response to the OQA findings were documented in a Plant Position Report dated May 1, 1985, and in a Manager of Operations (MOO) response to the PPR dated May 6, 1985. The Plant Manager summarized the actions in response to the findings during a meeting on May 6, 1985, which included the following:

+ Based on the results of the OQA evaluation and the identified weaknesses, the licensee concluded that the present inspection procedures and practices are not in compliance with the YOQAP requirements. A task force was created to review the present inspection program and identify what changes are required to meet the YOQAP requirements. The review would assess whether the plant should continue with the peer inspection program or replace it with an independent onsite QC group. The task force had to complete its work and report its findings and recommendations to licensee management by June 7, 1985.

+ The MOO directed plant personnel to take immediate corrective actions to bring the current program into compliance pending the completion of long term fixes; and, to take the steps necessary to make the audit findings a licensee identified violation of regulatory requirements.

The Plant Manager implemented corrective measures in a memorandum to plant personnel dated May 9, 1985, which established interim compensatory QC inspection requirements. The interim requirements established the following: (i) defined the type of plant activities that would be subject to QC inspection and assigned the Department Supervisors responsibility for determining where QC inspections will be applied; (ii) defined the scope and frequency of QC inspections to be a minimum of 10% of the total activities selected by the supervisors for independent verification; (iii) issued a form to document QC inspection activities that meets the requirements of YOQAP Section XVII.C.1.a; and, (iv) defined the criteria for selection and qualification of the independent inspector. The interim measures were implemented on March 13, 1985 following completion of personnel training.

9.2 Findings

The inspector noted that the interim measures were implemented per the above requirements based on observation of work activities during the inspection period. The inspector identified no inadequacies with the corrective actions; however, the audit findings and corrective actions will be reviewed further by the NRC staff.

The inspector noted that the licensee's audit findings and actions appear to meet 4 of the 5 criteria established in 10 CFR 2, Appendix C for classifying an item as a licensee identified violation. The deficiencies were identified by the

licensee; the violations would fit a severity level 4 or less; although not required by regulation, the item was reported informally to the NRC; and, the corrective actions are appropriate and are being implemented in a reasonable time period.

However, it appears that the violations, in part, could reasonably be expected to have been prevented by the licensee's corrective actions from a previous violation (fifth criteria from Appendix C). The OQA 85-11 audit findings, Deficiencies 1 through 4, appear as a recurrence of NRC concerns identified during a July, 1983 inspection as Violation 83-22-05 (Item A of the Appendix to IR 83-22): failure to perform a meaningful number of independent inspections of maintenance activities, failure to document independent inspections, and failure to incorporate guidance in plant procedures regarding maintenance activities to receive independent inspections.

The corrective actions for violation 83-22-05, initially scheduled to be completed by May, 1984, were deferred to November 1, 1984 to allow additional time to upgrade the AP 0021 requirements and to train plant personnel on the proper performance of independent inspections for maintenance activities. Licensee corrective actions for violation 83-22-05 were inspected and found acceptable during an October, 1984 inspection (IR 84-23).

This item remains open pending further NRC review of the OQA audit findings, the licensee's corrective actions for the audit findings, and pending further review of the licensee's corrective actions for violation 83-22-05. NRC concerns in this area are tracked by inspection item 84-10-06.

10. Followup on Receipt Inspection Program Findings

The task force for the receipt inspection program completed its work by April 29, 1985 and submitted its findings and recommendations to plant management for review. The task force recommendations were accepted by plant management with minor changes on May 15, 1985 and a schedule for implementation of the recommendations was established. The actions to improve the receipt inspection program were summarized in letter FVY 85-48 as part of the licensee's response to the IR 85-11 violation.

The actions initiated by the licensee included: (i) proposed changes to procedures AP 0800, 0801, 0803, 0806 and DP 0811 to clarify procurement and receipt inspection instructions, provide revised checklists for receipt inspections, and provide inspection guidance for mechanical and electrical components; (ii) providing tools and a reference library for the receipt inspectors; (iii) providing two full time receipt inspectors; (iv) steps to improve the warehouse preventive maintenance program; and, (v) upgrade training program requirements and documentation. The following schedules were established: approve procedure revisions and new guidelines by July 10, 1985; complete additional formal training of receipt inspectors by July 31, 1985; and, implement the upgraded receipt inspection program by August 1, 1985. The inspector noted no discrepancies regarding the above corrective actions and schedules. A detailed review of these actions will be completed by NRC Region I and reviewed onsite on a subsequent inspection.

The task force recommended the termination of the second receipt inspections that were initiated on March 14, 1985 and performed on any material released for safety related work. This action was recommended based on (i) no significant problems identified during the second receipt inspections performed as of April 29, 1985; (ii) no cause for rejection identified during the second receipt inspection for the 11 items identified by the NRC, or for the 23 items identified by the licensee; (iii) the favorable engineering evaluations completed for all items as of April 29, 1985; and, the issuance of DI 85-01 to AP 0801, which provided additional interim guidelines for the receipt inspection process. The inspector had no further comment on this item.

The licensee identified 23 other purchase orders with questionable initial receipt inspections. The items from the purchase orders would be subject to a second receipt inspection and an engineering evaluation to assure no components of questionable quality were introduced into the plant. The engineering evaluation will be completed by June 30, 1985. This item will be followed on a subsequent inspection.

The Manager of Operations addressed the importance of complete and accurate documentation of safety related activities in a memorandum to the Vermont Yankee organization dated May 16, 1985. The responsibility of supervisors to assure procedures and forms are clear and unambiguous was also emphasized. The inspector had no further comment on this item.

The NRC staff requested information under 10 CFR 50.54(f) by letter dated April 25, 1985 regarding the apparent falsification of receipt inspection records. The results of an investigation completed by the law firm of Ropes & Gray were provided in letter FVY 85-47 dated May 23, 1985. The investigation concluded that there was no evidence that any receipt inspector or other Vermont Yankee personnel knowingly falsified receipt inspection records or attempted to mislead any reader of a completed receipt inspection checklist. Inadequate inspection checklists and the inconsistent methods used to fill out the forms contributed to the inaccurate receipt inspection records. Licensee management did not provide adequate instructions, procedures and training to inspection personnel. This item will be reviewed further by the NRC on a subsequent inspection.

Documentation of the licensee's actions and evaluations were forwarded to NRC Region I for additional review and evaluation. The above items are collectively considered open pending completion of the licensee corrective actions and subsequent review by the NRC (Follow Item 85-18-04).

11.0 Equipment Qualification

11.1 Conax Penetration Seals

The Technical Services Superintendent notified the inspector on May 17, 1985, of a problem with potential safety significance. The licensee's engineering organization received notification from the Conax Buffalo Corporation, a maker of penetration seals, that an assembly failed an environmental test that was

performed for another facility. The failure was caused by the use of teflon in the potting compound installed in the penetration assembly to seal around the electrical leads. The potting compound passed all environmental tests except the exposure to radiation. Failure of the penetration assembly could cause a failure in the electrical circuit carried by the assembly, and a failure of the primary containment boundary. No further details were available regarding the test or the model number of similar penetrations that may be installed at the plant. It is known that teflon breaks down at radiation exposures in excess of 1.0 E+4 rads. The item was reviewed by plant and engineering personnel.

The licensee reported to the inspector on May 22, 1985 that four Conax penetration assemblies using teflon in the potting compound were installed in the outer bulkhead of the drywell personnel access hatch. The licensee determined that failure of the teflon material in those assemblies would not create a significant safety hazard because the penetrations are installed only in the outer bulkhead; the penetrations do not carry any safety class electric circuitry (gaitronics, ARM and utility box leads); and, a failure of the sealant material in the penetration would not result in the release of any additional radioactive material since the inner air lock bulkhead would act as the containment boundary. Nonetheless, the licensee plans to repair or replace the four assemblies during the 1985 outage.

The inspector reviewed the four penetration assemblies on the air lock, toured the torus area, and reviewed purchase order documentation for Conax penetrations installed in the air lock and on the torus shell. The air lock penetrations contained teflon sealants and teflon insulation. The other Conax penetrations contained polysulfone sealant and polyimide (kapton) insulation. No other penetrations of the type susceptible to failure were identified.

The inspector had no further comment on this item at the present time. The licensee is reviewing this item for reportability under 10 CFR Part 21. This item is considered open pending: (i) inspector review of the engineering evaluation to identify the Conax assemblies that use teflon; and, (ii) completion of the licensee's review for reportability and subsequent review by the NRC (Unresolved Item 85-18-05).

11.2 Scram Discharge Level Instruments

11.2.1 The licensee informed the inspector on May 9, 1985 of a problem identified with the environmental qualification of level transmitters used on both the North and South scram discharge instrument volumes. The level transmitters (LTs 2-3-231A through 231H) are used to provide level alarm, rod block and scram functions based on high level conditions in the instrument volume. The Rosemont 1153B transmitters with remote diaphram seals were originally qualified as part of the reactor protection system (RPS) for environmental temperatures up to 180 degrees F. Temperatures in the Reactor Building can reach a maximum of 243 degrees F near the South SDV and 188 degrees F near the North SDV following a break in the HPCI steam line. The licensee tracked resolution of the problem through Nonconformance Report 85-11 dated April 24, 1985, which required an engineering resolution within 7 days in accordance with the new environmental qualification (EQ) procedures implemented in April, 1985 at the plant.

The licensee completed a justification for continued operation for NCR 85-11 to address the operability issue on the instrument volume level instruments. The instrument volume level transmitters were included in the EQ program for consistency with the treatment of the RPS. The instrument volume scram function, and thus, the level instruments, are not relied upon to mitigate a high energy line break or to achieve safe shutdown. The probability of a high level occuring in the scram instrument volume concurrent with a HELB and scram is remote. There is no mechanism that could cause a high instrument volume level as a result of a HELB.

A fracture mechanics analysis previously performed for the HPCI steam line determined that the line is not susceptible to sudden, catastropic failures. However, to provide additional assurance of early detection of a leak in the HPCI line, the licensee initiated additional visual surveillance of the steam line from the main steam tunnel to the HPCI room. In the unlikely event that the steam line should break during the period of operation until the outage, the licensee will declare the scram system inoperable and follow Technical Specifications 3.1.A and Table 3.1.1 to insert all control rods within four hours.

Therefore, operation until the 1985 outage is justified. Steps will be taken to qualify the level transmitters by insulating the remote diaphram seals prior to startup from the 1985 outage. The inspector had no further comments regarding the JCO.

11.2.2 The reportability of this item was discussed with the licensee and NRC personnel. The inspector informed the licensee that the staff's initial evaluation was that the item should be reported to the NRC under 10 CFR 50.49(h). The licensee reviewed the item and concluded that no report under 50.49(h) is required since the problem was not one of the original items for which schedular extension beyond March 31, 1985 was required.

Reportability of a newly identified EQ issue on a piece of equipment could be determined based on a review of the problem in accordance with the VYNPC Environmental Qualification Plan. The program for reviewing and dispositioning EQ issues was submitted to the NRR staff for review by letter FVY 85-36 dated May 17, 1985. The program plan requires that EQ issues be categorized and dispositioned with an NCR within 7 days, including the development of a JCO. If the issue cannot be satisfactorily resolved after 7 days, the technical specification action statement would be followed, if applicable, for the equipment in question. A plant shutdown required under the technical specification action statements would be reportable.

This item is considered open pending (i) completion of licensee actions to qualify the LT 231 instruments; (ii) further NRC staff review of the Vermont Yankee EQ Plan method for dispositioning new equipment EQ issues; and (iii) further review of the 10 CFR 50.49 reportability requirements (Unresolved Item 85-18-06).

12.0 Management Meetings

A meeting was held at the request of the licensee on May 23, 1985 at the NRC Region I Office. Attendance at the meeting was as shown in Appendix I of this report. The meeting was held to discuss, in general, the NRC findings regarding the receipt inspection program at the plant (reference NRC Region I Inspection Report 85-11), and specifically, to discuss the NRC perception that licensee personnel were less than fully open with NRC inspectors regarding known problems in the receipt inspection area. The meeting was beneficial for both parties to review the need for open communications, and assurances were obtained that future licensee identified problems would be communicated to NRC inspection personnel.

Preliminary inspection findings were discussed with plant 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.

Appendix I

May 23, 1985 Meeting Attendees

Vermont Yankee Nuclear Power Corporation

Mr. W. F. Conway, President and Chief Executive Officer

Nuclear Regulatory Commission

Mr. T. E. Murley, Region I Administrator
Mr. J. M. Allan, Deputy Regional Administrator
Mr. R. W. Starostecki, Director, Division of Reactor Projects
Mr. T. T. Martin, Director, Division of Radiation Safety and Safeguards
Mr. S. D. Ebneter, Director, Division of Reactor Safety
Mr. W. J. Raymond, Senior Resident Inspector