U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 84-21

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: September 19 - October 31, 1984

Inspectors: William J. Raymond 11/14/84
W. J. Raymond, Senior Resident Inspector date

Approved by: L. E. Tripp 11/28/84
L. E. Tripp, Chief, Reactor Projects date
Section 3A, Projects Branch 3

Inspection Summary:

Areas Inspected: Routine, unannounced inspection on day time and backshifts by the resident inspector of: action on previous inspection findings; physical security; routine power and shutdown operations, including logs, records and operational status of safety systems; maintenance activities; surveillance testing; LER 84-21; response to IE Bulletin 84-02; Rosemont 1153B pressure transmitters; status of NUREG 0737 items; Appendix R, Item III.G procedures for Alternate Shutdown Systems; response to events involving inoperable diesel generators and contaminated material in the unrestricted area; followup of inspection and evaluation of the vessel internals; and, personnel adherence to plant procedures. The inspection involved 202 hours on site.

Results: No violations were identified in 11 of 13 areas inspected. One apparent violation was identified regarding the failure of maintenance personnel to properly secure the separator assembly to the core shroud, paragraph 14. A concern was identified regarding the operation of the plant in an unanalyzed condition from September 16-18, 1984. Three apparent violations were identified regarding the failure to control material released to an unrestricted area within the owner controlled area, paragraph 15.

DETAILS

1.0 Persons Contacted

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

Mr. R. Leach, Chemistry and Health Physics Supervisor
Mr. D. Reid, Operations Superintendent
Mr. J. Pelletier, Plant Manager

2.0 Status of Previous Inspection Findings

2.1 (Closed) Follow Item 83-14-03: Documentation of Evaluations of Drywell Conditions. The inspector reviewed a memorandum from the Maintenance Supervisor dated January 9, 1984 which documented his evaluation of the drywell coating and the containment spray nozzles, based on inspections completed during the 1983 outage. No unacceptable conditions were identified. This item is closed.

2.2 (Closed) Violation 84-10-03: Failure to Complete Testing Per OP 4374. The licensee's response to this item in FVY 84-99 dated August 9, 1984 stated that OP 4374 would be changed to include instructions for the torus level instrument calibrations to preclude a recurrence of the event. The insepctor reviewed OP 4374 Revision 13, inclusive of Department Instruction (DI) 84-5, and noted that the procedure now requires that water used to fill the transmitter reference legs be at ambient temperature with the torus room where the level instruments are located. The procedure instructions which require that the Shift Supervisor be notified if the calibration cannot be completed were also clarified. This item is closed.

The licensee took exception in his response to the staff's conclusion that OP 4374 had been violated during the performance of the calibration on May 8, 1984. This matter will be addressed in a separate letter to the licensee.

2.3 (Open) Violation 84-08-06: High Pressure Coolant Injection (HPCI) System Inoperable. The following licensee actions as described in letter FVY 84-79 dated July 7, 1984 were completed: the importance of complete and detailed log entries was addressed in a memo to licensed personnel dated June 10, 1984; the violation was discussed in the September monthly meeting with the Shift Supervisors; the event and the HPCI logic circuits were discussed in training classes fo Re-qualification Cycle 5 during the period from September 10 to October 16, 1984; and, OP 3100, Revision 12, Reactor Scram Emergency Procedure, was changed by DI 84-10 to require that the logic system resets on control room panels CRP 9-3 and 9-4 be activated while establishing/verifying the 'final conditions' during the recovery phase following a scram.

Changes to Alarm Response Procedure OP 3140 had not been completed as of October 31, 1984. The Operations Engineer stated that a revision to the procedure will be completed in November, 1984 to require that the HPCI high level trip condition be reset following receipt of the 'HPCI High Level Trip' annunciator.

The NRC letter dated June 8, 1984 requested the licensee to address the results of his evaluations regarding the HPCI system design feature wherein the high level isolation logic can remain in a tripped condition after the initiating condition has cleared, without providing indication of its status to the reactor operator. The response dated July 7, 1984 did not fully respond to the request, but stated that the April 16, 1984 occurrence would be considered by the Control Room Design Review Committee in accordance with the licensee's previous NUREG 0730, Supplement 1 commitments. During meetings with the Operations Superintendent and the Plant Manager, the inspector determined that the April 16, 1984 event has been assigned as a Category 1 human engineering discrepancy. This is the most significant category of discrepancy (out of 4) that resulted in an actual event caused by operator error. The control room design analysis is presently scheduled to be done by May, 1985 and the results will be reported to the NRC by July, 1985.

This item remains open pending completion of changes to OP 3140, and pending completion of the control room design review to resolve the concern with the current design of the HPCI isolation trip and reset features. This item will be reviewed further on a subsequent NRC inspection.

2.4 (Closed) Violation 84-08-07: Failure to Follow OP 0100 to Reset the HPCI Logic. Actions were completed in accordance with the response made in FVY 84-79 dated July 7, 1984 to add a specific sign-off in the instructions to reset the initiation and isolation logics for safeguard systems. The change was made in Revision 15 of OP 0100. Instructions in OP 0100 were also clarified and supplemented to require that two licensed senior licensed operators review and concur in any proposed change in the sequence of steps specified by OP 0100, as well as any proposed deletion of any step. Such deviations must be explained in the procedure. This item is closed.

2.5 (Closed) Violation 84-08-01: Deviations from the DC Distribution System Lineup Specified in OP 2145. Actions were taken as specified in FVY 84-79 to change OP 2145 (Revision 8) to specify that the DC circuit breakers for the RHR-33 and the Startup Transformer Deluge valve electrical supplies be 'closed'. This item is 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, authorization, badging, escorting, personnel and vehicle searches.

3.1 The inspector reviewed the compensatory measures implemented on October 5 and 20, 1984, while security equipment was in a temporarily degraded condition. During a meeting with the Plant Manager on October 10, 1984, the inspector noted

that the licensee has provided funds to hire a consultant to study and evaluate the security hardware, and make recommendations for system improvements.

Security measures are discussed further in paragraph 16 below.

No violations were identified.

4.0 Shift Logs and Operating Records

Shift logs and operating records were reviewed to determine the status of the plant and changes in operational conditions since the last log review, and to verify that: (1) selected Technical Specification limits were met; (2) log entries involving abnormal conditions provided sufficient detail to communicate equipment status, correction, and restoration; (3) operating logs and surveillance sheets were properly completed and log book reviews were conducted by the staff; (4) Operating and Special Orders did not conflict with Technical Specification requirements; and, (5) Jumpers (Bypasses) did not create discrepancies with Technical Specification requirements and were properly approved prior to installation.

The following plant logs and operating records were reviewed periodically during the period of September 19 - October 31, 1984:

- -- Shift Supervisor's Log
- -- Night Order Book Entries
- -- Control Room Operator Log
- -- Auxiliary Operator Log
- -- Control Point Log
- -- Jumper/Lifted Lead Log
- -- Maintenance Request Log
- -- Switching Order Log
- -- Shift Turnover Checklists
- -- Radiochemistry Analysis Log
- -- Standing Orders dated July 17, 1984
- -- RE Log Typer-Core Performance Log
- -- Potential Report Forms dated September 16, September 30, and October 15
- -- Manager of Operations Directives 84-02, 84-03 and 84-04

No violations were identified.

5.0 Inspection Tours

Plant tours were conducted routinely during the inspection period to observe activities in progress and verify compliance with regulatory and administrative requirements. Tours of accessible plant areas included the Control Room Building, Reactor Building, Diesel Rooms, 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 0036, Shift Staffing. Inspection reviews and findings completed during the tours were as described below.

5.1 Fluid Leaks and Piping Vibrations

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.

No violations were identified.

5.2 Plant Housekeeping and Fire Prevention

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 welding, cutting and grinding operations on the North and South banks of hydraulic control units. No inadequacies were identified.

No violations were identified.

5.3 Equipment Tagout and Controls

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 Orders 84-1278, 84-1279, 84-1203 and 84-1209 were reviewed and no discrepancies were noted.

No violations were identified.

5.4 Feedwater Sparger Performance

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 September 30, 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. The plant was shutdown for 11 days in September and no data was collected from the feedwater nozzles until the plant returned to steady state operations at power.

No violations were identified.

5.5 Safeguard System Operability

Reviews of the Residual Heat Removal, Residual Heat Removal Service Water, High Pressure Coolant Injection, Core Spray, and Reactor Core Isolation Cooling (RCIC) systems were conducted to verify that the systems were properly aligned and fully

operational in the standby mode. Review of the above systems 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 violations were identified.

5.6 Radiological Controls

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 RWP requirements. Radiation surveys were conducted by the inspector during plant tours to confirm proper posting of radiological areas. Work activities associated with the following RWPs were reviewed: 84-2655, 84-2656, 84-2651, 84-2676 and 84-2684. No inadequacies were identified.

Apparent violations in the area of radiological controls are discussed in paragraph 15 below.

5.6.1 The Health Physicist from the Vermont State Health Department notified the inspector by telephone on October 12, 1984 of a potential discrepancy regarding the calibration of the plant effluent monitor. The concern arose based on his observations of the effluent monitor calibration during a recent visit to the plant site, in which he noted an apparent difference in wall thickness between the pipe that houses the effluent monitor at the plant discharge structure and the test stand used to calibrate the monitor. The wall thickness of the pipe in the test stand was less than the pipe that houses the monitor. If the wall thickness at the bottom of the housing is the same as at the top, then the effluent monitor calibration would be incorrect and result in a detector response that underestimated a radiation source due to the additional attenuation in the pipe wall.

This matter was discussed with the Chemistry and Health Physics Supervisor on October 15, 1984. The licensee stated that, based on his recollection and previous review of this same question, the pipe that houses the monitor at the discharge structure has a transition piece on the lower sections to provide a lower schedule, thinner walled pipe on the bottom of the housing. The thinned walled pipe was incorporated in the original design for the monitor to increase its sensitivity, and the test stand was built to the dimensions of the lower section. The licensee stated that a drawing or other form of documentation would be provided for inspector review.

The inspector noted that the licensee does not routinely discharge radioactive effluents to the Connecticut River and that the effluent monitor is normally not used. This item is considered open and will be reviewed further on a subsequent inspection to verify that the geometry of the effluent monitor calibration stand is the same as the detector housing (IFI 84-21-01).

5.7 Jumpers and Lifted Leads (J/LL)

Implementation of the following J/LL Requests was reviewed to verify that controls established by AP 0020 were met, no conflicts with the Technical Specifications were created and installation/removal was in accordance with the requests: J/LL Request Nos. 84-165 through 84-172, and 84-127.

No violations were identified.

5.8 Analyses of Process Liquids and Gases

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. The boron concentration in the standby liquid control supply tank was maintained within technical specification limits.

No violations were identified.

6.0 Operational Status Reviews

The operational status of standby emergency systems and equipment aligned to support routine plant operation was confirmed by direct review of control room instrumentation. Control room panels and operating logs were reviewed for indications of operational problems. Licensed personnel were interviewed regarding existing plant conditions, facility configuration and knowledge of recent changes to 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.

The plant was in cold shutdown at the start of the inspection period to investigate the condition of the reactor vessel internals. The plant was restarted on September 18, 1984 following completion of the investigation and verification of proper seating of the steam separator assembly. Power escalation was halted at 50% full power (FP) and the plant was taken to cold shutdown to repair the inboard isolation valve on the 'A' steam line. Power operation resumed on October 2, 1984, and continued until October 23, 1984, when a shutdown to cold conditions was commenced due to both emergency diesel generators being inoperable. The diesels were repaired and the shutdown was terminated at 26% FP. Operation at full power continued through the remainder of the inspection period.

6.1 Recirculation Weld Leakage Detection System

The recirculation weld leakage detection system was operable during the inspection period, with status information available from all six detectors. No indications of recirculation system weld leakage was detected.

No violations were identified.

6.2 Main Steam Isolation Valve (MSIV) Failure

During routine testing of the MSIVs at about 50% FP on September 29, 1984, inboard valve MSIV 80D closed in 16.5 seconds, which was in excess of the 5 seconds required by the technical specifications. The valve was closed and declared inoperable, and the outboard valve on the 'D' steam line was closed. The plant was taken to cold shutdown to allow entry into the drywell to repair the valve. The valve was repaired and tested satisfactorily on October 1, 1984 and routine operations continued.

Inspector view of the maintenance completed on MSIV 80D is discussed further in paragraph 8 below.

No violations were identified.

6.3 Failed Reactor Vessel Level Instrument

During routine operations at full power on October 14, 1984, plant operators noted at 4:28 P.M. that reactor vessel level channel LT2-3-58B was reading 21 inches lower than the actual level of 160 inches (referenced to the top of the active fuel). Further investigation determined that the 6 amp, 24 VDC ELMA power supply for the transmitter was degraded. The channel was declared inoperable, and a half trip was put in on the reactor, the recirculation pumps, and primary containment isolation groups 1 through 4 at 6:10 P.M. per the technical specifications. Technicians installed and tested a spare power supply and LT2-3-58B was declared operable at 8:25 P.M. on October 14, 1984.

A supervisor reviewing the completed work on October 15, 1984 determined that the above power supply installed on October 14, 1984 was rated for 2.5 amps and was not suitable as a replacement. Protection systems were placed in a half trip condition (as above) at 12:10 P.M. on October 15, 1984. The 2.5 amp power supply was removed from the channel. A faulty capacitor was identified and replaced in the original failed 6.0 amp supply. LT2-3-58B was tested satisfactorily and returned to service, and the half trip conditions were cleared at 3:15 P.M. on October 15, 1984.

The inspector had no further comments regarding the operational aspects of this item. The maintenance activity is discussed further in paragraph 8 below.

No violations were identified.

6.4 Control Rod 18-11

During a control rod pattern exchange at about 50% FP on October 24, 1984, plant operators tried to pull control rod 18-11 to position 48 for the first time since the August 6, 1984 startup from the refueling outage. The control rod would not move beyond position 46. Rod 18-11 was left at position 46, along with the three other symmetrical rods in the group. Control rod 18-11 was considered operable since the rod was capable of full insertion in response to a scram signal.

The licensee conducted friction testing on control rod 18-11, which confirmed that the rod was stopping between positions 46 and 48. The licensee determined that the position indication circuits for the rod were functioning properly. The control rod responded satisfactorily during scram time and friction testing at cold conditions. A new drive mechanism was installed for control rod 18-11 during the refueling outage. The control rod was uncoupled from the drive for the change-out, but was not removed from the core.

The licensee's review of the problem with control rod 18-11 was still in progress at the end of the inspection period. The rod group containing 18-11 will remain at position 46. The licensee's engineering group will evaluate whether continued long term operations with the rod at position 46 will adversely affect the core analyses. No adverse effects are expected since the control rods have very little reactivity worth at position 46.

This item is considered open and will be followed on a subsequent inspection to review the licensee's evaluation and final resolution of the problem with control rod 18-11 (IFI 84-21-02).

6.5 Loss of Both Diesel Generators

During routine operations at 100% full power (FP) on October 22, 1984, a generator lockout condition occurred on the 'A' Diesel Generator at 1:55 P.M. The diesel was not running at the time. The lockout was caused by a faulty generator differential relay. The 'A' Diesel Generator was declared inoperable and alternate system testing was completed in accordance with Technical Specification 4.10.B.1. by 9:05 P.M. on October 22, 1984, which included a satisfactory test on the 'B' Diesel Generator. No spare differential relays were available on site and further work on the 'A' diesel was deferred until October 23, 1984.

A generator lockout condition occurred on the 'B' Diesel Generator at 1:40 A.M. on October 23, 1984 due to a failed generator differential relay. The differential relay caused a spurious activation of the lockout relay. The diesel was not running at the time. Plant load was reduced to 90% FP to begin a shutdown to cold conditions due to both diesels being inoperable. Technical specification 3.5.H requires that the plant be in cold shutdown within 24 hours.

The 'B' Diesel Generator was declared operable at 6:18 P.M. on October 23, 1984 following the completion of repairs and operability testing. Plant shutdown was halted at 21.6% full power at 6:23 P.M. and preparations were made to return to full load. Plant load was held at 40% FP to perform a rod pattern exchange and to complete routine maintenance on the recirculation motor generator sets. The 'A' Diesel Generator was returned to service following repairs and operability testing at 7:40 P.M. on October 24, 1984.

The licensee determined that zener diodes in the operating circuits of the Westinghouse Type SR-1 differential relays had failed in both diesel generator control circuits and had caused spurious operation of the generator lockout relays. The zener diodes were replaced in the relays for both diesels. The licensee concluded that the failures occurred because the diodes reached an end-of-life condition.

The inspector had no further comments regarding the operational aspects of this item. This event is discussed further in paragraph 15 below.

No violations were identified.

7.0 Surveillance Activities

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

-- OP 4113.02, MSIV Full Closure Test, September 30 and October 1, 1984
-- OP 4364, RCIC Steam Line High Flow Calibration, October 16, 1984

The following item warranted followup by the inspector.

7.1 The licensee completed a calibration of the reactor core isolation cooling (RCIC) system steam line flow Bartons, 13-83 and 13-84, on October 16, 1984 per OP 4364. The trip setpoints for the redundant instruments were found out of specification high at -198 and -200 inches of water. The technical specifications require that the instruments trip at less than -195 inches of water to provide for an isolation of the RCIC system in the event of a break in the steam supply line. The instruments were returned to an operable status by adjustment of the trip setpoints as each discrepancy was identified. The deficiencies were reported to the Shift Supervisor and a Potential Reportable Report form was submitted for evaluation.

The inspector reviewed the results from the October 16, 1984 test and the OP 4364 monthly test results for both transmitters for testing during the period from August, 1983 until September, 1984. No other instances were identified where the as found trip setpoint was in excess of the technical specification limit. The trip setpoints were found in excess of the licensee's administrative limits on various occasions, but no trend in the calibration data was apparent that would indicate that a change in the calibration frequency would be warranted. The Instrument and Control Foreman stated that future results from OP 4364 would be reviewed for adverse trends as a part of the routine surveillance program. The inspector had no further comment on this item.

No violations were identified.

8.0 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 84-1743, HPCI 14 Valve Disc Replacement
-- MR 84-1851, MSIV 80D Bushing and Guide Rod Repair
-- MR 84-1931, LT2-3-58B Power Supply Repair
-- MR 84-1968, DG 'A' Differential Relay
-- MR 84-1970, DG 'B' Differential Relay
-- MR 84-1776, Station Battery 'A' Cell Replacement

No violations were identified. The following items required inspector followup. The repairs associated with the diesel generators are discussed further in paragraph 15 of this report.

8.1 While in cold shutdown for the reactor vessel internals inspections, the licensee replaced cells 2, 5 and 53 in the 'A' main station battery as recommended by the YAEC engineering group and documented in a August 1, 1984 memorandum to the Senior Operations Engineer. The engineering recommendation was made following an inspection by the battery vendor, C&D Company, on July 7, 1984 of the batteries.

The vendor determined that a mechanism referred to as "mossing" is in progress in the cells, which eventually leads to a loss of cell capacity, as evidenced by low specific gravity and cell voltage. Cell #11 of the 'A' Battery was replaced on June 1, 1984 (refer to Inspection Report 84-08) due to low specific gravity. The licensee determined from the battery discharge tests completed during the refueling outage that no loss of capacity has occurred on either main station battery. YAEC engineering concluded that the cells in the station batteries do not have to be replaced immediately as long as the specified battery conditions are maintained. However, the engineering group recommended that any cell whose voltage and specific gravity falls below the technical specification values be replaced immediately. The parameters for cells 2, 5 and 53 were greater than the technical specification requirements, but were lower than other cells and gradually trending downward.

The inspector had no further questions on this item at the present time. NRC concerns regarding the long term operability of the station batteries are tracked by inspection item 84-08-03.

No violations were identified.

8.2 While in cold shutdown for the vessel internal examinations, the licensee disassembled the HPCI turbine steam admission valve, V23-14, for inspection due to evidence of leakage past the valve seat during previous plant operation. V23-14 is a 10 inch diameter Walworth Type 5247 PSB, split-disc gate valve. The licensee found some clearance between the disc and the valve seat, which would account for the seat leakage observed when steam was supplied to the valve. The stellite ring on the disc seating surface had several (5) small cracks across the face of the ring on the stem side of the disc. The disc wedge is cast chrome moly-steel, type ASTM A-217, Grade Spec WC6. The seating ring is made from P No. 4, Grade 1 stellite.

A replacement disc was obtained under Purchase Order (PO) No. 23715 and machined under Materials & Service Procurement Request No. 84-166 by Ranor, Inc. Stores QC personnel determined on September 26, 1984 that the machined disc did not meet the PO requirements upon its return from Ranor, Inc., in that no as-found and as-left dimensions were returned with the completed work. The vendor was contacted and the required data was telecopied to the site.

A new disc assembly was installed and the valve was tested and declared operable at 11:30 P.M. on September 28, 1984.

No violations were identified.

8.3 During routine surveillance testing of the main steam isolation valves (MSIV) on September 30, 1984, inboard valve MSIV 80D failed to close in less than the required 5 seconds. Two of the four valve actuator guide rods were found galled during a drywell entry at about 50% full power. The plant was shutdown at 6:25 P.M. on September 30, 1984 to replace the actuator plate bushings and guide rods.

All four guide rods and the bushings on the spring separator plate and the actuator plate were replaced. The new bushings were made of bronze instead of steel. The new guide rods had a different finish than the old ones. Both changes were recommended by the valve manufacturer, Rockwell, Inc., as a result of past experience with galling between the guide rods and the bushings. The recommendation to install new bushings was also made by the General Electric Company in SIL #309, Supplement 2 dated July 27, 1984. MSIV 80D was the last of the inboard valves to have the old style materials. The materials were scheduled for change-out in 1985 under the licensee's preventive maintenance program.

No violations were identified.

8.4 During routine operations at 100% FP on October 14, 1984, reactor vessel level transmitter LT2-3-58B failed due to a failed ELMA 24 VDC, 6 amp power supply, Catalog No. 164C5261P002. Technicians installed a spare power supply and returned the channel to an operable status at 8:25 P.M. on October 14, 1984. An I&C supervisor reviewing the completed work on October 15, 1984 determined that the power supply installed on October 14 had a Catalog No. 164C5261P001 and was rated for 2.5 amps. The replacement supply was operating at a 2.6 amp steady state load, was thus underrated for the application, and was unacceptable as a replacement-in-kind for the original power supply. An unreviewed, unapproved change in the circuit design had inadvertently been made to the safety related level channel. Based on the above, the level channel was declared inoperable and appropriate actions were taken until a proper power supply could be installed.

The inspector reviewed this event with the Senior I&C Engineer. Three types of Elma power supplies are available in stores with part numbers that differ only in the last digit. Only two of the three types, 2.5 and 6.0 amp units, are currently in use at the site. Although the part numbers are recorded on the

power supply chasis, vendor drawing #C-5965D, which showed the difference between the supplies with part numbers ending in P001 and P002, was not available to I&C technicians in the shop files. The power supplies are identical in obvious outward appearances and differ in weight by about 5 lbs. Another factor that contributed to the error was that the Master Parts List (MPL) had both the P001 and P002 units listed as suitable for use in the Analog Trip System, when the P001 units are intended for use only in the torus level channel.

The licensee took action to place a copy of the vendor drawing in the shop files, annotated with the instructions that only the P002 units are suitable for us in the Analog Trip System. A request has been submitted to the Stores Department to correct the MPL.

The unreviewed, unapproved change made to the LT2-3-58B circuit design on October 14, 1984 was contrary to the requirements of AP 0021 and Technical Specification 6.5.A. This is considered a violation of technical specification requirements identified and corrected by the licensee. The inspector had no further comments on this item.

9.0 Review of Licensee Event Report (LER) 84-21

The licensee submitted LER 84-21 on October 16, 1984 to report the reactor power/flow anomaly that was first observed during routine power escalation on September 11, 1984. Testing at power on September 16, 1984 indicated that the cause for the anomaly was **carryunder due to improperly secured steam** separator assembly. Following a plant shutdown on September 18, 1984 and subsequent disassembly of the reactor internals, the licensee verified that the separator assembly was not properly secured to the shroud. NRC review of the anomaly and the licensee's investigation of the event is reported in Inspection Report 84-18 and in paragraph 14 below.

The inspector reviewed LER 84-21 and noted that the report accurately described the event and the licensee's findings. The report met the reporting requirements of 10 CFR 50.73. The inspector noted that the report was submitted in accordance with item 10 CFR 50.73(a)(2)(ii)(C) ... "discovery that the reactor is in a condition not covered by the plant's operating and emergency procedures". The licensee concluded that even though the reactor internals were in a configuration that invalidated the reactor system models used in the safety analyses, the separator misconfiguration had a negligble impact on the results of the safety analyses. The inspector had no further comment regarding LER 84-21.

No violations were identified.

10.0 Review of IE Bulletin 84-02

The inspector reviewed the licensee actions taken in response to IE Bulletin 84-02, as described in letter FVY 84-89 dated July 19, 1984, concerning replacement of General Electric HFA relays. Previous NRC reviews of this item are documented in Inspection Report 83-27.

The licensee determined that there are a total of 332 HFA relays used in safety related applications at the plant. Of the 332 relays, there are 321 located in the control room, with 145 in AC circuits and 176 in DC circuits. Of the 145 relays in AC circuits, 136 are in the reactor protection system (RPS). None of the remaining 9 relays are normally energized in AC circuits. As of July, 1984,the coils in 129 of the AC relays had been changed out within the last three years and replaced with either Century Series or other non-lexan coils.

The licensee stated that the 7 relays with normally energized AC coils which have never been replaced will be replaced during the refueling outage. Further, the 176 DC relays and the 40 AC relays with coils that were replaced during the last two years will be upgraded with Century Series coils during the 1985 outage. The remaining 11 AC relays are located outside the control room and are in circuits that are not normally energized. These relays are used in protection circuits for the diesel generators (2), switchgear 8 and 9 (2), and for the 4KV buses (7).

The inspector reviewed the actions taken during the last outage and noted that the coils in the following 6 AC relays were replaced in RPS circuits: 16A-K7A, 16A-K5C, 16A-K6C, 5A-K5B, 16A-K44D, and 5A-K12D. Six relays were replaced instead of 7, because two relays (16A-K18A and 18B) initially scheduled for replacement were determined to be model 12 HFA65D69F time delay relays, that used full wave rectifiers to convert the RPS AC supply to DC. The licensee intends to contact the relay vendor to determine whether replacement kits are available for these relays. The coil in relay 16A-K7A was replaced even though its coil had been replaced in 1981.

The inspector determined during discussions with Maintenance Department personnel that the 11 relays used in switchgear and diesel generator applications will also have their coils replaced with the Century Series type during the 1985 outage.

The licensee reviewed his normal surveillance program and concluded that the monthly functional tests verify that the necessary relays operate to assure a reactor trip. All safety related AC and DC HFA relays with non-Century Series coils were inspected during the last outage. The licensee concluded that based on past experiences with the HFA relays, any additional increased surveillance was not justified. The licensee provided sufficient justification in his response for continued plant operation until all normally energized relay coils are replaced.

No violations were identified.

11.0 Rosemont 1153B Transmitters

The licensee notified the inspector on September 28, 1984 that information regarding a potential defect with Rosemont 1153B transmitters had been received from the vendor and was being reviewed to determine whether the item should be reported under CFR Part 21. The transmitters had apparently failed a LOCA qualification test conducted by Rosemont. When the transmitters were pressurized

internally during the tests to about 5.0 psig, a leakage path was identified in the threaded connection between the sensor module and the electronics unit. The leakage path would allow moisture to enter the electronics unit and affect operation of the transmitter. Rosemont reported to the licensee in early September that the problem applied to 1153 Series B transmitters manufactured after January 10, 1984 and that users of the units would have to complete evaluations for reportability under Part 21.

The inspector reviewed this item with the Engineering Support Supervisor on September 28, 1984 and again on October 31, 1984. The licensee's initial review of the information from Rosemont determined that no immediate concern existed at VY, but that additional engineering evaluation was warranted and the matter was forwarded to YAEC engineering for action.

Two 1153B transmitters were installed at the plant during the 1984 outage and are used in safety related applications in reactor vessel level channels LITS 2-3-7A&B. The Rosemont units replaced Yarway instruments in that application which were not environmentally qualified and for which Justification for Continued Operation (JCO) 26 and 27 were written (reference VY letter to the NRC - FVY 84-74 dated June 29, 1984). The transmitters at VY are mounted outside the drywell on the Jet Pump instrument racks on the Reactor Building 252 foot elevation. The instruments provide a dual function of post accident vessel water level indication (local and remote) and a permissive function at 2/3 core height to allow LPCI injection water to be diverted from the core to the containment cooling mode of operation in the post accident recovery phase of a LOCA.

The licensee takes credit for use of the instruments in the LOCA analysis. The licensee determined that the identified failure mechanism would not be a concern at VY since a high pressure steam environment would not exist in the Reactor Building following a postulated LOCA. The licensee also considered the possible breaks in the high energy lines in the vicinity of the transmitters and concluded that: (i) the line breaks would be detected and isolated; and, (ii) the function of the transmitters would not be used following those accidents. Based on the above, the licensee concluded that there was not operational safety concern given the available information.

YAEC engineering performed a complete evaluation of the information provided by Rosemont and confirmed the previous conclusions that no safety concerns existed for the applications of the 1153B transmitters at VY. YAEC engineering recommended, after consultation with Rosemont, that a bead of silicone sealant be applied to the threads of the transmitter to provide additional assurance that no moisture intrusion would occur. Rosemont purportedly will test the transmitters with that configuration to verify it corrects the problem observed initially. The licensee decided to not apply sealant to the transmitters until the configuration was tested by Rosemont and the test results are available for evaluation and followup.

The inspector had no further comments on this item.

No violations were identified.

12.0 Followup of TMI Action Plan Items

The NUREG 0737 - Tnree Mile Island Action Plan requirements listed below were reviewed to determine the status of licensee actions and the schedule for completion of the items.

12.1 TAP Item II.K.3.57

The licensee stated in WVY 80-170 dated December 15, 1980, that no actions would be taken on this item until symtematic operator guidelines regarding manual actuation of the automatic depressurization system (ADS) are developed by the BWR Owners Group and approved by the staff. The Senior Operations Engineer stated on September 26, 1984 that the status of VY actions to add and/or clarify instructions on the use of the ADS function in the emergency operating procedures would be determined. This item will be followed on a subsequent inspection (IFI 84-21-03).

12.2 NUREG 0737, Supplement 1 Items

The NRC staff issued a Confirmatory Order to the licensee dated June 12, 1984 and modified it by letter dated September 28, 1984 to confirm the completion schedule for the following TMI Items:

	ITEM	SCHEDULE
12.2.1	Safety Parameter Display System	
	+ implementation plan	2/ 1/85
	+ establish operational date by	2/ 1/85
12.2.2	Control Room Design Review	
	+ submit program plan	5/ 1/84
	+ summary and implementation schedule	7/ 1/85
12.2.3	Emergency Response per RG 1.97	
	+ submit report	10/31/84
	+ schedule to implement	10/31/84
12.2.4	Upgrade EOPs	
	+ PGP to NRC	7/ 1/84
	+ implement EOPs	6/ 1/85
12.2.5	Emergency Response Facilities	
	+ TSC functional	complete
	+ OSC functional	complete
	+ EOF functional	11/ 1/85

The inspector noted that the licensee has submitted a program plan for the Detailed Control Room Design Review in accordance with 12.2.2 above. Licensee actions on TMI items will be reviewed further on subsequent routine inspections.

No violations were identified.

13.0 Review of Alternate Shutdown Procedures

The inspector reviewed the status of the licensee's actions to make operational the shutdown panels that were installed in accordance with his commitments to the requirements of Item III.G of Appendix R to 10 CFR 50. The schedular requirements of 10 CFR 50.48 required that the alternate shutdown equipment be operational prior to startup from the 1984 refueling outage. The inspector reviewed the actions taken to complete testing on the alternate shutdown panels; establish procedures for completing a plant shutdown remote from the main control room; and, train plant operators on the alternate shutdown procedures and panels. The inspector's review of these items were not completed during the inspection period and will be completed on a subsequent routine inspection. The findings from this review were as discussed below.

13.1 Alternate means to shutdown the reactor without reliance on the control room and the cable vault were provided in control panels, alternate power sources, and control and power transfer switches located in the Reactor Building, the switchgear room, the Turbine Building and the 'A' Diesel Generator room. Two main control panels for the residual heat removal (RHR) and reactor core isolation cooling (RCIC) systems were provided on the 280 foot and 213 foot elevations of the Reactor Building, respectively. An operability demonstration for the RCIC panels, CP-82-1 and CP-82-3, was conducted under actual steaming condition in accordance with the system operating procedure on August 7, 1984 during plant startup from the refueling outage.

The licensee considered all alternate shutdown systems and equipment to be operational for startup from the refueling outage.

13.2 The following procedures were issued to provide the instructions necessary to operate and test the alternate shutdown panels, and to complete a plant shutdown from outside the control room:

+ OP 3126, Shutdown Using Alternate Shutdown Methods, Revision 0, August 3, 1984
+ OP 4126, Diesel Generator Surveillance, Revision 15, July 10, 1984
+ OP 4124, RHR and RHRSW System Surveillance, Revision 15, August 2, 1984
+ OP 4121, RCIC System Surveillance, Revision 16, August 3, 1984

The normal surveillance procedures for the diesels, the RHR system and the RCIC system (OPs 4126, 4124 and 4121) were revised to include instructions to complete the monthly valve operability and system performance tests from the alternate shutdown panels. There is no requirement that the alternate shutdown panels be used, but the test can be run from the panels at the discretion of the operating shifts as a training item.

OP 3126 was issued to replace the previous procedure for shutting down remote from the control room, OP 3131. The inspector noted on October 22, 1984 that OP 3126 was issued and distributed to plant personnel. However, OP 3131 was also still on file in the control room, the TSC and in the Operations Department. OP 3131 should have been deleted from the active files in accordance with

Procedure Change No. 287 on August 1, 1984. The record clerks controlling the above files were notified and actions were taken to remove OP 3131. The control and distribution of procedures in accordance with AP 0831 requirements will be reviewed further on a subsequent inspection (UNR 84-21-04).

13.3 The inspector interviewed the Operations Supervisor and the Operations Training Supervisor to review the training given to plant operators on the new procedures. All procedures were made available in the Communications Book for operator review. Additionally, OP 3126 was discussed and reviewed with all Operations shifts in a classroom review of the new procedures and equipment as part of the post-outage operator training sessions. Additional classroom training is planned to review the system surveillance procedures.

The licensee stated that the surveillance procedures have been used to actually operate plant equipment to demonstrate that the procedures will work as written. However, no pre-operational type test was performed or is planned for OP 3126. The Operations Supervisor stated on October 15, 1984 that a dry run of the procedure with an Operations crew was scheduled. This exercise was completed on October 26, 1984 as discussed below. The inspector noted that OP 3126 was reviewed by Operations personnel during its development and an extensive field walkdown of the procedure was completed to verify that the instructions were correct and would achieve the desired objectives.

13.4 The inspector witnessed an Operations shift crew walk through a dry run of OP 3126 on October 26, 1984. The crew had practiced with the procedure for several days prior to the actual test. Several significant procedural improvement items were identified by the Operations crew during the practice drills and incorporated into the test run on October 26, 1984. Based on the test witnessed on October 26, 1984, the licensee demonstrated that the alternate shutdown equipment and the then available procedures were adequate to conduct a plant shutdown to hot conditions from outside the control room. The improvement items and problem areas noted below were identified either by the licensee during the OP 3126 reviews by the operations crew, or by the inspector based on his review of OP 3126.

13.4.1 OP 3126 was orginally written to be performed by a shift supervisor plus 4 operators, for a minimum crew of five people. The licensee's minimum staffing for back shifts includes 6 operators, 1 shift engineer, 1 HP technician and the guard force. OP 3126 was written for possible use in the event of a fire in the control room or the cable vault. The 5 man fire brigade would be staffed by the Shift Engineer, 2 guards and 2 operators. Since members of the fire brigade could not be used for shutdown activities, that leaves only the Shift Supervisor plus 3 operators to complete the actions required by OP 3126. The testing completed on October 26, 1984 was completed by the Shift Supervisor and 3 operators, with the Shift Supervisor performing the functions designated for Operator #3 in OP 3126, operation of the RCIC shutdown panel.

13.4.2 OP 3126 requires that an Alert emergency be declared in accordance with OP 3501 if OP 3126 must be implemented and the control room abandoned. For the staffing described in 13.4.1 above, there would not be enough personnel

to implement the actions required by OP 3501 and OP 3126 concurrently. Additionally, access to the Nuclear Alert System, which is used to provide the notifications to the States, is not available outside the control room.

OP 3125, Classification of Emergencies, requires that an Alert be declared if a fire (or other casualty) causes an evacuation of the control room. OP 3125 further requires that a Site Area Emergency be declared if the control room is evacuated and the control of shutdown systems is not established locally within 15 minutes. The minimum time taken by the shift crew to establish control of the plant with the alternate shutdown panels was 32 minutes. It thus appears that a Site Area Emergency should be declared immediately if OP 3126 is implemented and it is not likely that access to the control room will be re-established within 15 minutes.

13.4.3 OP 3126 did not designate where the shift supervisor should be stationed to perform the procedure, but to assume any location where he can maintain adequate communications, command and control. The procedure should be revised to specify alternative locations in the plant where the shift supervisor should be stationed to coordinate the shutdown activities. The locations should be listed in order of decreasing effectiveness to allow selection of the best locations if the casuality precludes access to any one.

13.4.4 The instructions in Note 5 of Appendix A to OP 3126 for operation of the RCIC panel referred the operator to three instruments from which RCIC system flow can be read locally for operation of the system. RCIC system flow could be read from only one of the three indications, by taking delta-P from FE-13-56 and using Figure 2 of the procedure. FE-13-58A on the alternate shutdown panel was covered over and inoperable on October 26, 1984, and there was no flow indicator FE-13-56 on the instrument racks adjacent to the shutdown panel.

13.4.5 The Caution statement in Step 5 of Appendix L warns the operator on what position the SRV Local Operation Switch should be in to preclude inadvertent operation of the 'C' SRV when connecting the temporary 125 VDC power supply. The Local Operation Switch was not labelled in accordance with the procedure instructions and could be a source of confusion for the operators and cause inadvertent operation of a safety relief valve.

13.4.6 The shift crew noted that extra copies or pertinent sections of OP 3126 should be pre-positioned to be available to the crew for use during the shutdown activities at each major panel. Additionally, labelling could be added or improved on some of the minor panels where the operator must complete actions directed by the procedure (for example, the location of pressure switches PS-2-134A/B/C/D in the Turbine Building).

13.4.7 The inspector conducted an independent review of OP 3126 and the three surveillance procedures to verify that the instructions were adequate to operate the alternate shutdown equipment. This review was still in progress at the conclusion of the inspection period and will be completed during a future routine inspection. Inspector comments identified during this review are discussed above and were provided to the licensee.

Licensee actions to incorporate or resolve the items listed in sections 13.4.1 through 13.4.6 above will be reviewed on a subsequent inspection (IFI 84-21-05).

14.0 Separator - Shroud Head Bolting

Plant operators noted an anomaly in the expected relationship between core power and core flow during power escalation on September 11, 1984. Reactor power did not increase by 45 megawatts as expected at core flows in excess of 42 million lbs per hour (mpph). There was a corresponding increase in vessel downcomer water temperature by about 2 degrees F.

The core power/flow relationship returned to expected values as core flow decreased below 42 mpph during a power decrease to 80% FP for routine testing on September 16, 1984. The core delta-P corresponding to 42 mpph flow would provide the force required to lift the separator assembly. The apparent leakage out of the core shroud would alter the expected power/flow relationship by raising the annulus water temperature and thereby decrease core inlet subcooling. The control room operators made a 50.72 notification to the NRC Duty Officer at 11:30 A.M. on September 16, 1984 based on possible operation in an unanalyzed condition. The licensee concluded that leakage out of the shroud area was the most probable cause for the core power/flow anomaly, which, in turn, was possibly caused by the separator/shroud head lifting off the shroud.

The licensee continued plant operation at 95% FP on September 16 and 17, 1984 while the observations from the September 16, 1984 testing were reviewed further. Administrative limits were placed at 95% FP and 40 mpph total core flow. The licensee's bases for continued plant operations were reviewed in a series of conference calls with the NRC staff on September 17, 1984. The licensee notified NRC Region I at about 5:00 P.M. on September 17, 1984 that the plant would be taken to cold shutdown to inspect the reactor internals.

The licensee began a controlled plant shutdown from 95% FP at 2:00 A.M. on September 18, 1984 and the plant was taken to refueling shutdown conditions to inspect the attachment of the in-vessel steam separator/shroud head assembly to the core shroud. Plans were made to inspect the upper internals and evaluate the following potential sources of carryunder: (1) inaccurate water level measurement resulting in lower than normal levels within the separator and increased leakage to the annulus region; (2) loose shroud head bolts allowing the shroud head to lift when the delta pressure across it overcame the deadweight of the assembly; (3) failure of the separator or dryer assemblies resulting in increased delta pressure, decreased water level within the separator, and increased leakage to the annulus region; and, (4) failure of the core spray sparger piping allowing hot fluid to enter the annulus region from within the shroud.

14.1 Licensee Evaluation Results and Conclusions

A detained examination of the vessel internals in accordance with OP 2500.01 was completed and video-taped during the inspection period. The inspector

witnessed portions of the exam ations while they were in progress and reviewed the video-tapes for the insepction of all major components. The items inspected included: the top of fuel assemblies; annulus region around top of jet pumps; separator assembly; dryer assembly; and, the core spray piping external to the shroud. The inspection findings are summarized below.

14.1.1 A detailed examination was completed of the separator hold down bolts to note the orientation of the T-bars, the engagement of the bolts with the hold down bolts lugs, the number of threads between the lock nut and the tensioning nut, and the as-found position of the retainer nuts. The shroud head bolts were orientated properly with respect to the shroud hold down lugs, but were not tight against them. All 36 shroud head bolts had approximately 1/4 to 5/8 inch clearance between the bolt and the core shroud lugs. This clearance would allow the shroud head to lift by about 3/16 to 7/16 inch. Licensee calculations based on the noted clearances confirmed that the amount of lift necessary to increase the carryunder was consistent with the amount of lift allowed by the loosened shroud bolts.

14.1.2 The initial inspection revealed evidence of what appeared to be steam cutting on the shroud/shroud head flange. The markings were limited to a small section of the shroud flange near bolt #20. The affected area was approximately 1/4 inch deep by 4 inches long on the outside surface of the shroud/head mating surface. Detailed examination and evaluation of the area was completed after the separator assembly was removed from the shroud. No evidence of steam cutting of the shroud to shroud head seating surface was identified.

14.1.3 There was no structural damage noted on the steam separator and dryer assemblies, or on the core spray piping. There was no evidence of wear or vibrations on the components inspected. There was some evidence of galling on both separator/shroud head alignment pins. No damage was identified that required repair.

14.1.4 The licensee reviewed the procedure used to reassemble the reactor, OP 1201, Assembly of the Reactor and Drywell Systems, Revision 9, dated May 24, 1984. The instructions in revision 9 were essentially the same as those used in previous years and have been used successfully at least 12 times in the past to complete vessel assembly. Procedure step 12 contains a four part set of instructions to tighten the hold down bolts. One sign-off for step 12 signifies that all 36 hold down bolts were tightened. Step 12 includes instructions to apply downward pressure with the head bolt wrench to disengage the spring retainer nut from the tensioning nut and then to turn the wrench until the hold down bolt is tight.

If the procedure is followed exactly as written by a worker having a complete understanding of the bolt and how it operates, then the instructions in OP 1201 would be adequate to complete the task. However, OP 1201 did not provide any warning that a failure to maintain downward pressure on the bolt wrench could result in incomplete tensioning of the bolts. If downward pressure is not maintained on the wrench, then the retainer nut can rise up to engage with the tensioning nut to give one the incorrect impression that the T-bar is engaged against the hold down lugs.

14.1.5 The maintenance crew who completed the vessel assembly on July 28, 1984 in accordance with OP 1201 was interviewed by the licensee. The crew consisted of two workers and one team leader. The team leader and one worker had previous experience in installing the separator assembly in accordance with OP 1201. One worker did not have prior experience in separator installation, but worked with the experienced worker to tighten the first 10 hold down bolts. The workers then worked independently to tighten the remainder of the bolts. The licensee determined from the interviews that one worker did not have a complete understanding of the bolting process.

14.1.6 Corrective actions were taken to preclude recurrence. Detailed briefings were held with the maintenance crew regarding the proper bolting sequence prior to completing the vessel reassembly during this inspection period. A spare bolt was used during the training demonstrations. Changes were made to OP 1201 to ensure proper bolt tensioning and shroud head seating during installation of the separator assembly. QC checks were included in the revised procedure to use the underwater tv equipment to inspect each bolt for proper engagement by noting the number of threads between the tensioning and lock nuts. Additionally, the bolt to lug engagement is inspected in at least four locations around the circumference of the shroud. The reactor was subsequently reassembled during which proper bolt tension and shroud head seating were verified. Plant startup commenced on October 1, 1984.

14.1.7 The licensee determined the following regarding the as-found vessel configuration and the potential consequences: (1) carryunder preheated the vessel downcomer water to approximately 2 degrees F higher than normal and thereby changed the anticipated neutron performance by approximately 0.2% reactivity. This was less than the 1% delta reactivity requirements of Technical Specification Section 3.3.6 regarding reactivity anomalies; (2) the as-found separator configuration invalidated the reactor system models used in the station safety analysis since these models do not assume a flow path from the upper core plenum volume directly to the vessel downcomer volume. However, the magnitude of the separator misconfiguration had a negligible impact on the results of the station safety analysis; (3) General Electric calculations showed that the predicted seismic loads could have been satisfactorily handled by the latched but not tightened shroud head bolts with a factor of safety of twice that required by the design basis; and, (4) the shroud head could not move or tip enough to contact any other component. Thus the consequences of a seismic event would not have been increased and no damage would have occurred to the core shroud, the shroud head guide pins or the core spray piping. The above conclusions were supported by an evaluation completed by YAEC engineering, as documented in a September 26, 1984 memorandum from J. D. Candon, NED 84-149. Based on the above, there were no adverse consequences to the public health and safety.

The licensee reported the results of his investigation in event report LER 84-21. The licensee concluded that the root causes which resulted in the improper installation of the separator/shroud head assembly at the end of the refueling outage in July, 1984 were: (1) a combination of improperly trained maintenance personnel and a lack of sufficient instructions in the vessel assembly procedure; and/or, (2) incomplete seating of the shroud during installation.

The licensee's evaluation of the separator bolting problem was still in progress at the conclusion of the inspection. The results of this evaluation will be formalized and documented in a Plant Information Report (PIR), which is scheduled to be completed by mid-November, 1984. This item is considered open pending completion of the PIR and subsequent review by the NRC (IFI 84-21-06).

The failure to properly bolt the separator/shroud head assembly to the shroud flange in accordance with the instructions in OP 1201 on July 28, 1984 was contrary to the requirements of Technical Specification 6.5.A (VIO 84-21-07).

15.0 Review of Plant Events

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

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

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

-- circumstances associated with the release of radioactive material and actions to control and contain the material;

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

-- verification that notifications were made to the NRC and in accordance with 10 CFR 50.72 and 50.73, as applicable.

Events reviewed during this period included the loss of both emergency diesel generators during full power operations and the discovery of radioactive material in an unrestricted area within the licensee's owner controlled area.

15.1 Inoperable Diesel Generators

During plant operations at full power on October 22-23, 1984, two apparently random failures of separate and independent differential protection relays caused both emergency diesel generators to be inoperable. The diesels were in a standby condition, but were not operating when the failures occurred.

The diesels became inoperable when a generator lockout condition occurred as a result of spurious operation of the generator differential relays. The generator lockout conditions were annunciated in the main control room. The differential relays monitor the difference in current between the generator output and the load side of the bus tie breaker, and are provided in the electrical protection scheme to protect the generator and the 4KV emergency bus against a fault on any of the three phases. An actual fault condition could not have existed at the time that the lockout conditions occurred since the diesels were not running.

The first failure occurred on the 'A' diesel generator at 1:55 P.M. on October 22, 1984. The 'A' diesel was left inoperable pending receipt of parts to repair the differential relay and operability testing was satisfactorily completed on the 'B' diesel generator. Testing of ECCS equipment in accordance with Technical Specification 3.5.H was also completed. The 'B' diesel subsequently failed at 1:40 A.M. on October 23, 1984. A plant shutdown to cold conditions was begun as required by Technical Specification 4.10.B by decreasing plant load by about 10% FP.

An Unusual Event was declared at 1:40 A.M. in accordance with OP 3125 since the loss of both diesels required that the plant be shutdown within 24 hours. The emergency was terminated at 4:37 A.M. on October 22, 1984 based on agreement with the States that no offsite protective actions should be necessary. The actions to terminate the emergency were in accord with the requirements of OP 3500. The licensee reported this event to the NRC Duty Officer in accordance with CFR 50.72 at 1:57 A.M. on October 23, 1984.

Plant load was decreased slowly as investigation and repair of the diesel generator protection circuits continued. During the period when both diesels were inoperable, the following immediate and delayed access sources of AC power to the 4KV emergency buses remained operable and available; (1) power from the offsite 115KV grid network was available to the 4KV buses throught the startup transformers. This is an immediate access source of power. The feed to the 4KV buses would automatically (fast) transfer from the unit auxiliary transformer to the startup transformer following a loss of generation at VY; (2) power from the offsite 345KV grid network was available to the 4KV buses through the main and unit auxiliary transformers as a delayed access source. Power could be supplied into the plant in a reverse feed through the transformers once the transformers are separated from the main generator by disconnecting the isolated phase buses; and, (3) power from the Vernon Hydroelectric Station can be supplied to either 4KV bus #3 or #4, independent of either offsite grid network. The Vernon supply is a delayed access source of power.

In addition to the above sources of AC power, the licensee concluded that both diesel generators could still be used during the period of "inoperability" by clearing tags on the diesel generator tie breaker, removing the generator differential relay, and running the diesel without differential protection. The inspector independently verified on October 22, 1984 that both diesel generators could be placed in service within about 10 minutes had it been necessary. The operations required to clear tags 84-1278 and 1279 included racking up and closing the bus tie breakers and restoring DC control power by closing a switch in the diesel local control panel.

The VY generation capacity is a large fraction of the electrical load for Vermont, but a small percentage of the total capacity of the REMVEC distribution network. Thus, a sudden loss of VY generation (i.e., reactor trip) would not likely cause a loss of the offsite grid.

Plant shutdown was terminated at 22% FP at 6:23 P.M. on October 23, 1984 when the 'B' diesel generator was returned to service following repair of the differential relay. The 'A' diesel generator was subsequently returned to service on October 24, 1984 following repair of its differential relay.

The spurious operation of the generator differential relays was caused in each instance by a zener diode that failed for no apparent reason. The zener diodes are a part of the operating circuit in the Westinghouse Type SA-1 differential relays and provide surge suppression for the silicone controlled rectifier (SCR) firing network. The generator lockout condition and hence, the loss of diesel operability, was annunciated in the main control room for each failure.

The control circuits for each diesel are supplied from separate and independent sources: the 'A' diesel is powered from a dedicated 125 VDC battery system, DC-2AS, located in the diesel room; the 'B' diesel generator is supplied from one of the 125 VDC main station batteries through Bus DC-1. The DC supplies were not cross tied at the time of the failures. The licensee monitored the performance of the diesel differential relays and continued an investigation of other potential causes for common mode failure. This evaluation was still in progress at the conclusion of the inspection. A recorder was installed on the DC control power supply for the 'B' diesel to monitor for voltage spikes. No anomalous conditions were noted on the DC source after 8 hours of monitoring. The licensee did note the presence of a peak-to-peak "ripple" on the DC supplies that ranged from 5 to 8 volts, which was not considered unusual or significant in relation to the operation of the differential relays.

The differential relays that failed were original equipment and there have been no previous failures or changes made to the relays. The calibration and operation of the diesel control circuits are checked each refueling outage by VY maintenance personnel and on a staggered test basis by the licensee's relay department. No anomalous conditions were noted in the calibration checks completed during the refueling outage which ended in August, 1984. Both diesels have been tested in a similar manner and have had about the same number of hours of operation. The licensee determined by a review of security records that there were no personnel in the diesel rooms at the time of the failures. This finding would suggest that 2-way radio operation had no effect on the control circuits. Technicians from the licensee's relay group performed checks on the generator protection circuits and determined that the protection relays feeding the 86 lockout relay were operating satisfactorily.

A suppression circuit associated with the 86 lockout relays in both diesels was discovered to be installed incorrectly on October 23, 1984. It is likely that the circuit was faulty since initial plant construction. Diodes were installed in the direction opposite that required to provide surge protection. The surge protection for the 86 lockout relay was not shown on plant drawings since it is a feature supplied by the relay vendor. After consultation with Westinghouse, the licensee reversed the surge suppressor (diode) on the 86 lockout relay for both generator protection circuits. The change was completed as corrective maintenance under AP 0021, even though no vendor print existed to show the proper orientation of the diode. This design change was reviewed and accepted by the

Plant Operations Review Committee (PORC) on October 23, 1984 as part of the Committee's review of the event. The possible effects on the differential relay caused by the previous lack of surge suppression for the lockout relay will be reviewed. An 86 auxiliary relay in the lockout circuit will also be examined for possible effects on the differential relay. The 86 auxiliary relay provides for a 0.35 second time delay in the de-energization of the 86 lockout relay after it is actuated.

The relay manufacturer no longer makes the SA-1 relay with zener diodes in the operating circuit. The SCR suppression design was changed to a resistor-capacitor (RC) circuit some time after the units in use at VY were procured. The circuit design change was proportedly made to correct reliability problems with the relay cuased by spurious failures of the zener diodes. The changes were made to improve the SA-1 relay to qualify it for Class 1E applications. The licensee was not notified by the vendor that a SA-1 design change was recommended for Class 1E applications. Further information from the relay vendor is required to evaluate the significance of the design change and its relation, if any, to the recent failures at VY.

The NRC issued Information Notice (IN) 83-63 as a result of problems experienced with the RC circuits in the modified SA-1 relays. The problems occurred as a result of defective (leaky) capacitors. VY reviewed this Notice upon receipt in 1983. The review documented on form VYAPF 0028.02 dated November 2, 1983 incorrectly concluded that no Westinghouse Type SA-1 relays were installed at VY. Supplement 1 to IN 83-63 was not reviewed in detail due to the results of the review for the original Notice. The concerns raised in IN 83-63 were reviewed by the licensee on October 23, 1984 and checks were made on the differential relays, as applicable. No discrepancies were identified. The inspector toured the facility and verified that no other Westinghouse Type SA-1 relays are installed at the plant. This tour included a review of protection installed in the control room, the switchgear rooms, the diesel rooms, the turbine building, the recirculation motor generator sets and the relay house. The licensee's actions to review and correct the inadequate review of IN 83-63 will be followed on a subsequent inspection (IFI 84-21-08).

No definitive cause was identified for the zener diode failures. The licensee's preliminary conclusion was that the diodes reached end of service life. The inspector noted the licensee's conclusions and stated that the essentially simultaneous failure of two independent components by end-of-life was possible, but very highly improbable. The PORC met on October 23, 1984 to review the relay failures. The Committee concluded upon review of the available information that there were no operational safety concerns in declaring the relays (and hence the diesels) operable, or in resuming full power operation. Several recommendations were made regarding further review and evaluation of the failure. Based on the PORC's recommendation, the fix on the 'B' diesel was accepted at 6:23 P.M. on October 23, 1984, and the diesel was declared operable, as noted above.

Further actions to study the failure are planned by the licensee. The relay vendor has been contacted and a visit to the engineering offices is scheduled in early November to review the relay application at VY. The licensee will determine the feasibility of performing a destructive examination on one of

the failed zener diodes to determine its failure mechanism. The second failed diode was given to NRC Region I for independent evaluation. The evaluations and actions taken by the licensee to identify other potential common mode failure mechanisms will be followed. This item is considered unresolved pending completion of the licensee's evaluation and subsequent review by the NRC (UNR 84-21-09).

15.2 Radioactive Material In An Unrestricted Area

The Plant Manager notified the inspector at 2:19 P.M. on October 25, 1984 that a box containing radioactive material was identified on owner controlled property in an area referred to as the North 40. The initial survey results identified readings as high as 12 mRem/hr on contact with a bag of asbestos waste inside the box. The licensee reported this item to the NRC Duty Officer at 2:20 P.M. on October 25, 1984 in accordance with 10 CFR 50.72. Notifications were made to the State of Vermont.

The licensee initiated an extensive program to survey the various areas within the owner controlled fenceline. The survey identified other materials that were contaminated to various degrees, as discussed below. Actions were taken to control the materials. The materials identified in the owner controlled area did not create a hazard to public health or worker safety. The storage locations are an unrestricted area as defined in 10 CFR Part 50, but are within the licensee's owner controlled area and, thus, are not accessible to the general public.

The references below to an "LSA box" refer to a standard plywood box with dimensions of 4 ft X 4 ft X 8 ft, that is typically used for compacting and shipment of low specific activity material. The licensee also uses the same type of box for storage and disposal of "clean" asbestos waste.

15.2.1 Summary of Survey Results

Licensee technicians identified radioactive material in an LSA type box of asbestos waste during a routine survey on October 25, 1984 of a materials storage area north of the 115 KV switchyard. The surface of the LSA box had 'hot spots' at two locations with contact dose rates of about 3 mRem/hr. The highest dose rate inside the box was initially found to be 12 mRem/hr on contact with a bag of asbestos. Later surveys identified contact readings of 30 mRem/hr on the same bag. The box was not labelled as containing radioactive material.

The box was identified following the observation by a licensee employee on October 24, 1984 of a 'yellow' 55 gallon drum in the storage area. Technicians surveyed the drum in question on October 25, 1984 and determined that it was not contaminated. The technicians noted radiation readings from the box of asbestos after returning to the area to paint the barrel black.

Upon discovery of the radioactive material in the North 40, plant management instituted the following controls and restrictions that remained in effect pending completion of an investigation of the finding: (i) all movement of material from the plant to the owner controlled area was terminated; (ii) a

pile of scrap wood located Northwest of the 345 KV switchyard, which had recently been made accessible to plant employees to obtain scrap lumber, was deemed off limits pending further surveys and investigation; (iii) the guard force was posted to ensure no material was removed from either the wood pile or the storage area; and, (iv) plans were made to complete a detailed survey of materials in the owner controlled area. The survey included 21 boxes of "clean" asbestos waste that were in temporary storage near the cooling towers, waiting for shipment and disposal in the Brattleboto land fill.

Licensee surveys were completed using extremely sensitive radiation detection instruments capable of detecting very low levels of radioactivity, which included RM-14 ion chambers with HP-260 probes and Eberline PRM-6 scintillation detectors. Additional surveys from October 25-31, 1984, of the above storage area and a pile of scrap wood located northwest of the 345 KV switchyard, identified 23 items with varying degrees of fixed and removable radioactive contamination. A summary of the items identified in the owner controlled area is provided below. The estimates of total activity in each item were calculated by the licensee using measured counts or dose rates from the item, and either the gamma constant for Co-60, or the exposure rate approximation derived from the linear energy absorption coefficient in air (reference: Radiological Health Handbook, January 1970).

(1) one (1) unlabelled LSA box containing asbestos waste; 'hot spot' dose rates of 3 mRem/hr at two locations outside the box; maximum dose rate inside the box was 30 mRem/hr on contact with one bag of asbestos. No "general area" dose rates above background were identified by the licensee or the inspector during independent surveys. General area dose rates measured by the inspector around the box and over most of its surface were less than 0.5 mRem/hr. Total activity: about 20 micro-Curies (uCi) of Co-60.

(2) one box of remote operators removed from the reactor water cleanup system during a system modification several years ago; 4000 dpm measured with an RM-14 at one spot on the outside surface of the box due to activity inside the box; dose rates were less than 0.1 mRem/hr total activity; about 1.8 nano-Ci (nCi).

(3) one 55 gallon drum; less than 1000 dpm/100 sq-cm removable; 10,000 dpm fixed; total activity: 24.3 nCi.

(4) five 55 gallon drums; less than 1000 dpm/100 sq-cm removable, 'spot' dose rates of 0.15 mRem/hr to 0.8 mRem/hr; total activity: 8.1 to 65 nCi.

(5) one box with a cask lifting fixture; 0.2 mRem/hr at 1 cm from the surface of the box. lettering stenciled on the surface of the box was very weathered and illegible, and could have been a caution statement regarding radioactive material. less than 1000 dpm/100 sq-cm removable; total activity: 16 nCi.

(6) one LSA box bottom; 12,000 dpm/100 sq-cm removable; 50,000 dpm/100 sq-cm fixed; total activity: 22.5 nCi.

(7) barrel with shielded pipe; less than 1000 dpm/100 sq-cm removable; 0.2 mRem/hr; total activity: 16 nCi.

(8) two pieces of wood with fixed contamination of 5000 dpm and 12,000 dpm; total activity: 2.25 nCi and 5.4 nCi.

(9) one pice of wood; 12,000 dpm/100 sq-cm removable; total activity: 0.11 nCi.

(10) four sections of cable; 2000 to 5000 dpm/100 sq-cm removable;total activity: 0.45 nCi.

(11) white bell flange; less than 1000 dpm/100 sq-cm removable; 0.3 mRem/hr; total activity: 24.3 nCi.

(12) black barrel; less than 1000 dpm/100 sq-cm removable; 0.15 mRem/hr; total activity: 8 Nci.

(13) two 8 inch pieces of 2 inch diameter pipe; 5000 dpm/100 sq-cm removable; total activity: 2.25 nCi.

(14) lump of concrete from a gallon pail; less than 1000 dpm/100 sq-cm removable; 0.7 mRem/hr; total activity: 56.7 nCi.

Items (6), (8) and (9) above were found in the scrap wood pile. The other items were found in the storage area North of the 115 KV switchyard. After a detailed survey was completed of the materials and wood in the storage areas, an extensive survey was completed to check the ground beneath the materials for contamination. No widespread ground contamination was found. A few isolated spots of very minor contamination were detected and removed. The amount of dirt removed in each spot was much less than a shovel full.

The licensee requested all plant personnel who had taken wood from the scrap wood pile to return the material to the site for contamination surveys. No contamination was found on any of the material returned. The licensee developed a listing of all personnel on site and actions were in progress at the conclusion of the inspection to contact each person individually to ensure that anyone who may have removed wood from the pile had been covered by the contamination survey.

The initial survey of the 21 boxes of asbestos stored near the cooling towers revealed 11 boxes with slightly positive indications of activity above background (between 100 and 250 counts above background with an RM-14). The 11 boxes were set aside and opened for further investigation. No definite contamination was identified within the boxes. A few bags with miscellaneous refuse were found mixed with the bags of asbestos waste, and were removed.

15.2.2 Findings

The area North of the 115 KV switchyard has been used over the years to store miscellaneous material. Some examples of the materials stored there included the following: several dozen 55-gallon drums; concrete blocks and forms; a rack of miscellaneous electrical conduit; a pile of scrap wire and cable;

miscellaneous piping, valves and components; and, boxes of scrap material. The wood pile in the North 40 could have come from plant areas both inside and outside the radiation controlled area and has purportedly been accumulating there since the Summer of 1983. It was not possible to determine when any one piece of wood was added to the pile.

The material in the North 40 equipment storage area was apparently placed there several years ago. It is unlikely that any of the material was placed there since January, 1984, based on the "weathered" appearance of all items found contaminated. At some time in the past, the licensee used the North 40 storage area to store several items that had known quantities of low level contamination. Examples of these items included heat exchangers from the advanced offgas system, the lifting fixture for the FSV-1 high level waste cask, and turbine crossover piping. About three years ago, the licensee decided to move the known contaminated material inside the inner fence area. The cask lifting fixture was apparently missed during this effort. The licensee apparently maintained no written inventory of known contaminated material kept outside the radiation controlled area.

The licensee's review of this item was still in progress at the conclusion of the inspection and will be documented in a Plant Information Report. Based on the information available as of October 31, 1984, it appears that none of the contaminated items found in the owner controlled area were placed there since the licensee strengthened his administrative controls after finding radioactive material on the ground outside the North Warehouse on February 2, 1984 (reference NRC Inspection Reports 84-01 and 84-04). Based on the above, the additional controls over the release of material from the radiation controlled area (RCA) do not appear to have been compromised. The additional measures instituted by the licensee after the February, 1984 incident have been reviewed by the NRC and found adequate to prevent an inadvertant release of material from the RCA (reference NRC Inspection Reports 84-17 and 84-24). However, this item is considered open pending completion of the licensee's evaluation and subsequent review by the NRC (IFI 84-21-10).

None of the radioactive items identified during the surveys was controlled as radioactive material. The radiation levels from each of the radioactive items were sufficiently low so as not to cause a health hazard to plant workers who may have received an unintended exposure from the material. It is extremely unlikely that a worker was exposed to the 30 mRem/hr dose rate from the bag of asbestos inside the LSA box. None of the radioactive material present in the owner controlled area created a 'radiation area' as defined in CFR 20. However, the box of asbestos waste contained an estimated 20 uCi Co-60 and should have been controlled in accordance with the following requirements: area posting per 10 CFR 20.203(e); container labelling per CFR 20.203(f); and control of licensed material per CFR 20.207(a). The root causes for the lack of control of the material found in the North 40 appear to have been due to either (i) a failure to survey, or a failure to conduct an adequate survey, of the materials prior to their release from the radiation controlled area; and/or, (ii) a failure to have an adequate program to inventory and control low level radioactive material stored outside the RCA in an unrestricted area.

The failure to label the LSA box of asbestos with quantities of licensed material in excess of ten times the amount specified in Appendix C of CFR 20, and to post the North 40 storage area containing the LSA box, is contrary to the requirements of 10 CFR 20.203(f) and 10 CFR 20.203(e), respectively (VIO 84-21-11).

The failure to conduct an adequate survey to assess the level of radiation hazard of material released outside the RCA is contrary to the requirements of 10 CFR 20.201 (VIO 84-21-12).

The failure to control radioactive material stored in the unrestricted area located North of the 115 KV switchyard so as to prevent unauthorized removal is contrary to the requirements of 10 CFR 20.207 (VIO 84-21-13).

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17.0 Personnel Adherence to Procedures

The inspector met with the Plant Manager on September 20, 1984 to discuss the security event of September 19, 1984 and the inspector's concerns regarding personnel adherence to plant procedures. The licensee's review of the September 19, 1984 event determined that the maintenance work party leader did not refer to certain steps in OP 1200 until after the actions prescribed by the procedure were completed. The licensee's findings confirmed the inspector's observation that maintenance personnel on September 19, 1984 were relying more on their experience and knowledge of the job and were not diligently following the written procedures governing the activity. The inspector stated that the September 19, 1984 event appeared as another recent example where experienced personnel did not rigorously follow the established administrative controls (reference: NRC Inspection Report 84-20). The inspector requested the Plant Manager to review this matter to determine whether further actions are warranted to assure better compliance with established procedures.

The inspector met with the Plant Manager of October 2, 1984 to discuss this subject. The licensee had not concluded his evaluation at that time, but did discuss the results of the preliminary findings. Available statistics indicated that roughly one of three incidents identified in nonconformance reports, QA reports and NRC findings in 1983 were caused by personnel error. The trend for 1984 with only 6 months of data did not show an improvement. However, the total number of events was not high and further review of the statistics was necessary to determine their significance. The issue was discussed at a recent meeting with the plant department supervisors and will be considered further to determine what additional actions should be taken to lessen personnel error.

This item will be reviewed further on a subsequent inspection pending completion of the licensee's evaluation. Personnel adherence to procedures will be reviewed on future routine inspections (IFI 84-21-14).

18.0 Management Meetings

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