NOTICE
AS OF 20 MAY 1981
REGION I HAS NOT OBTAINED PROPRIETARY CLEARANCE IN ACCORDANCE WITH 10 CFR 2.790.

U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

Region I

50-271/810306
50-271/810320

Report No. 81-05

Docket No. 50-271

License No. DPR-28 Priority -- Category C

Licensee: Vermont Yankee Nuclear Power Corporation

1671 Worcester Road

Framingham, Massachusetts 01701

Facility Name: Vermont Yankee

Inspection at: Vernon, Vermont

Inspection conducted: March 2-March 31, 1981

Inspectors: William J Raymond 5/8/81
W. J. Raymond, Senior Resident Inspector — date signed

S J Collins 5/8/81
S. J. Collins, Resident Inspector — date signed

date signed

Approved by: Robert M Gallo 5/18/81
R. M. Gallo, Chief, Reactor Projects Section 1A, Projects Branch #1 — date signed

Inspection Summary:

Inspection on March 2-March 31, 1981 (Report No. 50-271/81-05)

Areas Inspected: Routine announced inspection, per T/I 2515/50, on regular and back-shifts by Resident Inspectors of: action taken on previous inspection findings; IE Bulletin and Circular followup; review of shift logs and operating records; plant tours; surveillance testing; maintenance activities; followup of events; review of periodic and special reports; observation of physical security; inspector actions based on a review of the status of licensee implementation of NUREG 0737 requirements; and PORC Meeting No. 81-14. The inspection involved 206 inspector hours onsite by 2 resident inspectors.

Results: Within the areas inspected no items of noncompliance were identified.

Region I Form 12
(Rev. April 77)

DETAILS

1. Persons Contacted

Mr. R. Branch, Assistant Operations Supervisor
Mr. P. Donnelly, Instrument and Control Supervisor
*Mr. R. Kenny, Mechanical Engineer
Mr. L. Goldthwaite, Instrument and Control Foreman
Mr. S. Jefferson, Reactor Engineering and Computer Supervisor
Mr. M. Lyster, Operations Supervisor
Mr. W. Murphy, Plant Superintendent
*Mr. J. Pelletier, Assistant Plant Superintendent
Mr. W. Penniman, Security Supervisor
*Mr. D. Reid, Engineering Support Supervisor
Mr. R. Sojka, Senior Operations Engineer
Mr. S. Vekasy, Senior Mechanical Engineer
Mr. G. Weyman, Chemistry and Health Physics Supervisor
Mr. W. Wittmer, Maintenance Supervisor

The inspector also interviewed other licensee employees during the inspection, including members of the Operations, Health Physics, Instrument and Control, Maintenance, Reactor Engineering, Security, Contractor and General Office staff.

*denotes those present at management meetings held periodically during the inspection.

2. Action Takén on Previous Inspection Findings

a. (Closed) Noncompliance (50-271/78-18-01): Failure to survey and handle off gas samples per procedure. The inspector witnessed the performance of an AOG sample at the steam jet air ejector at 10:00 A.M. on March 17, 1981. The sampling and analysis was conducted in accordance with OP 2611, Gaseous Radwaste, Revision 7, dated November 7, 1978. The inspector noted in particular that procedural precautions were followed in regard to surveying the sample and the use of plastic bags to transport the sample to the counting lab. This item is closed.

b. (Closed) Follow Item (50-271/80-17-07): S/RV Qualification Program Status and Schedule. The program status and schedule for providing seismic qualification data for safety and relief valve position indications was provided in WVY 80-170, dated December 15, 1980. The qualification plan for the safety valve acoustic accelerometers will be completed in the fourth quarter of 1981. Qualified pressure switches for the relief valves are expected to be received onsite and installed during the second quarter of 1981. Completion of the qualification program and review of qualification data will be followed for the individual NUREG 0737 items (open items for these cases are documented elsewhere). This item is closed.

c. (Closed) Unresolved Item (50-271/80-17-08): Licensee to upgrade AP 0150 to incorporate documentation of reactor water cleanup (RWCU) and recirc sample system leakage surveillance. A review of Revision 14 of VYOPF 0150.02 on March 11, 1981, showed that the RWCU and recirc sample systems were incorporated in the leakage surveillance program. This item is closed.

3. IE Bulletin Followup

a. For the IE Bulletins listed below, the inspector verified the following: that the written response was within the time period stated in the bulletin, that the written response included the information required to be reported, that the written response included adequate corrective action commitments based on information presented in the bulletin and the licensee's reviews, that licensee management forwarded copies of the written response to the appropriate onsite management representatives, that information discussed in the licensee's written response was accurate, and that corrective action taken by the licensee was as described in the written response. The following bulletins were reviewed:

(1) IE Bulletin No. 79-24, Frozen Lines, dated September 27, 1971

IE Bulletin (IEB) 79-24 requested the licensee to conduct a review to determine that adequate protective measures have been taken to assure that safety-related process, instrument, and sampling lines do not freeze during extremely cold weather conditions.

The inspector reviewed licensee internal memorandum which assigned IEB 79-24 response responsibility to Yankee Atomic NSD Engineering Office and VY Operations on October 2, 1979.

In their response, WVY 79-128, D. E. Moody to US NRC B. H. Grier dated October 30, 1979 , Vermont Yankee noted that adequate measures had been taken at the site to preclude freezing of safety-related process, instrument and sampling lines. The licensee further noted that difficulties had been experienced in the past with other support systems and that each of these areas had been satisfactorily resolved. The licensee's response indicated that no operational difficulties had been experienced during a recent nine day period of record breaking cold weather.

No inadequacies were identified.

(2) IE Bulletin No. 79-16, Vital Area Access Controls, dated July 30, 1979

As a result of an attempt to damage new fuel assemblies at an operating nuclear power facility IE Bulletin (IEB) 79-16 requested specific actions be taken by licensees to control access to vital areas.

The licensee responded to the NRC in letter WVY 79-102, D. E. Moody to US NRC B. H. Grier, dated September 12, 1979. The information provided deals with the security system at Vermont Yankee and is considered proprietory pursuant to 10 CFR 2.790. The inspector determined by document review that the licensee's response adequately addressed the concerns of IEB 79-16, the schedule for periodic licensee review of vital area access was discussed with the security supervisor and the results of an access control system functional test were reviewed by the inspector.

No inadequacies were identified.

b. Closeout of IE Circulars

The following IE Circulars were reviewed to ascertain if the following actions were taken by the licensee:

The Circular was received by licensee management.

A review for applicability was performed.

For Circulars applicable to the facility, appropriate corrective actions have been taken or are scheduled to be taken.

(1) IE Circular No. 79-08, Attempted Extortion, dated May 18, 1979

The inspector reviewed licensee memoranda forwarding IEC 79-08 to the site Security Supervisor for review on September 5, 1979. In a memo to file dated March 9, 1981, the Security Supervisor documented his review of the circular noting that Vermont Yankee does not hold the specific material addressed in IEC 79-08. The licensee reported that the systems which failed in this specific event are checked weekly by the guard force and that the guard force and plant personnel have been advised of this type of problem and the possible consequences during the site training program. (CLOSED)

4. Shift Logs and Operating Records

a. The inspector utilized the following plant procedures to determine the licensee established administrative requirements in this area in preparation for review of various logs and records.

-- AP 0001, Plant Procedures, Revision 6, dated September 25, 1979

-- AP 0150, Responsibility and Authority of Operations Department Personnel, Revision 14 dated December 19, 1980

-- AP 0153, Maintenance of Operations Department Logs, Revision 8, dated December 31, 1979

-- AP 0140, VY Local Control Switching Rules, Revision 4, dated Decmeber 19, 1980

-- AP 0020, Lifted Lead/Installed Jumper Request Procedure, Revision 4, dated October 16, 1980

-- AP 0021, Maintenance Requests, Revision 9, dated September 25, 1980

-- AP 0154, Control Room Night Order Book, Revision 5, dated January 7, 1980

-- AP 0030, Plant Operations Review Committee, Revision 6, dated January 17, 1980

The above procedures, Technical Specifications, ANSI N18.7-1972 "Quality Assurance Requirements for Nuclear Power Plants" and 10 CRF 50.59 were used by the inspector to determine the acceptability of the logs and records reviewed.

b. Shift Logs and operating records were reviewed to verify that:

-- Control Room logs and surveillance sheets are properly completed and that selected Technical Specification limits were met.

-- Control Room log entries involving abnormal conditions provide sufficient detail to communicate equipment status, lockout status, correction, and restoration.

-- Log Book reviews are being conducted by the staff.

-- Operating and Special orders do not conflict with Technical Specifications requirements.

-- Jumper/Lifted Lead log does not contain bypassing discrepancies with Technical Specification requirements and that modification are properly approved prior to performance.

c. The following plant logs and operating records were reviewed:

-- Shift Supervisor's Control Room Log: March 2-March 31, 1981

-- Night Order Book Entries: March 2-March 31, 1981

-- Maintenance Requests: 81-0268 thru 81-0388

-- Control Room Operator Round Sheet: Periodic reviews during inspection period.

-- Auxiliary Operator #1 and #2 Rounds Sheet: Periodic reviews during inspection period.

-- Equipment Status Log: Periodic reviews during inspection period.

-- RE Log Typer-Core Performance Log: Periodic reviews during inspection period.

-- Control Room Chemistry Log Sheets: January 23-March 4, 1981

-- Chemistry Lab Log Book: January 15-March 4, 1981

No items of noncompliance were identified. Except as noted below, the inspector had no further comments in this area.

During routine reviews of shift operating records on March 4, 1981, it was noted that a potential reportable occurrence report was issued on January 10, 1981, under report number PRO 3 (81). The item was reported under TS 3.2.3 and involved an engineering analysis which indicated the potential existed for the block wall enclosing the staircase on the 318 ft. elevation could fail during a seismic event. Initial evaluations concluded that failure of the wall could affect a Zone Radiation Monitor and the standby liquid control (SLC) system. Subsequent licensee review concluded that only the Zone Radiation Monitor could be affected by a collapse of the wall. The item was deemed not reportable under TS 3.2.3. An action item was initiated to provide additional support for the block wall.

The inspector reviewed the area in question and, in particular, the proximity of the wall to the SLC system. The inspector had no further comment on this item. No inadequacies were identified.

5. Plant Tour

The inspector conducted a tour of accessible areas of the plant including the Control Room Building, Turbine Building, Reactor Building, Diesel Rooms, Intake Structure, Security Gate Houses 1, 2 and Alarm Stations, Radwaste Building and Control Point Areas.

a. Monitoring Control Room Panels

Routinely during the inspection period, as required by T/I 2515/50, the inspectors conducted reviews of the control room panels. The following items were reviewed to determine the licensee's adherence to Licensee Technical Specification - Limiting Conditions for Operation and to verify the licensee's adherence to approved procedures.

-- Switch and valve positions required to satisfy LCO'S, where applicable.

-- Alarms or absense of alarms. Acknowledged alarms were reviewed with on shift licensed personnel as to cause and corrective actions being taken where applicable.

-- Review of "pulled alarm cards" with on shift personnel.

-- Meter indications and recorder values.

-- Status lights and power available lights.

-- Front panel bypasses.

-- Computer printouts.

-- Comparison of redundant readings.

No items of noncompliance were identified.

b. Radiological Controls

Radiation controls established by the licensee, including: posting of radiation areas, radiological surveys, condition of step-off pads, and disposal of protective clothing were observed for conformance with the requirements of 10 CFR 20 and AP 0503, Establishing and Posting Controlled Areas, OP 4530, Dose Rate Radiation Surveys and OP 4531, Radioactive Contamination Surveys.

-- Posted Radiation Work Permits were reviewed by the inspector to verify conformance with licensee procedure AP 0502, Radiation Work Permits: 81-0157, 81-0156, 81-0155, 81-0218 and 81-0221.

-- Stack and off gas sample analysis was reviewed by the inspectors to verify conformance with OP 0631 Radiochemistry, on March 17 and March 31, 1981.

No items of noncompliance were identified.

c. 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.

No inadequacies were identified.

d. Fluid Leaks and Piping Vibrations

Systems and equipment in all areas toured were observed for the existence of fluid leaks and abnormal piping vibration.

No inadequacies were identified.

e. Pipe Hangers/Seismic Restraints

During routine tours of the plant, pipe hangers and restraints installed on various piping systems were observed for proper installation, tension, and condition.

No inadequacies were identified.

f. Control Room Manning/Shift Turnover

Control Room Manning was reviewed for conformance with the requirements of 10 CFR 50.54 (k), Technical Specifications, AP 0152, Shift Turnover, AP 0150, Responsibility and Authority of Operations Department Personnel and AP 0036, Shift Staffing. The inspector verified, during the inspection, that appropriate licensed operators were on shift. Manning requirements were met at all times. Several shift turnovers were observed during the course of the inspection. All were noted to be thorough and orderly.

No items of noncompliance were identified.

6. Surveillance Testing

The inspector observed portions of the following surveillance tests to verify that testing was performed in accordance with technically adequate procedures, that results were in conformance with Technical Specifications and procedure requirements, that test instrumentation was calibrated, that redundant system(s) or component(s) were available for service, that work was being performed by qualified personnel, and that activities were in compliance with AP 4000, Surveillance Testing Control. Portions of the following surveillances were reviewed by the inspector:

-- RHR and RHR SW System Surveillance per OP 4124 on March 4, 1981

-- Diesel Generator Surveillance per TS 4.10.A.1.a on March 16, 1981

-- APRM Functional Testing per OP 4302 on March 27, 1981

-- Reactor Water Level ECCS-Initiation-Isolation Functional/Calibration on March 31, 1981

-- RCS Iodine Separation and Measurement per OP 0631 on March 7, 1981

-- AOG Sample and Analysis per OP 2611 on March 17, 1981

-- SBGTS Filter Testing per OP 4610 on March 9-11, 1981 (this item is discussed further in paragraph 8.d).

No items of noncompliance were identified.

7. Maintenance Activities

The inspector observed portions of the following maintenance activities to verify compliance with LCO requirements where applicable, that redundant components were operable, approved procedures were utilized, activities were controlled by qualified personnel, and compliance with AP 0021, Maintenance Requests, and AP 0200, Maintenance Program. Portions of the following activities were reviewed by the inspector:

-- MR 81-0279, March 4, 1981, Maintenance on RHR V10-16A, (see report detail 8.a).

-- MR 81-0319, March 15, 1981, PCIS 16A K2B, GE Relay replacement.

No items of noncompliance were identified.

8. Inspector Followup of Events

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

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

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

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

-- verification of correct operation of automatic equipment;

-- verification of proper manual actions by plant personnel;

-- verification of adherence to approved plant procedures;

-- verification of conformance to Technical Specification LCO requirements;

-- compliance with AP 0010, Occurrence Reports, when applicable.

Operational events reviewed during this inspection are discussed below.

a. <u>Repair of RHR Valve V10-16A, RHR Pumps A and C Minimum Flow Line Isolation Valve</u>

During a routine review of issued maintenance requests, the inspector noted MR 81-0279 was issued on March 4, 1981, authorizing maintenance on RHR Pump A and C minimum flow line isolation valve. Inspector review of the occurrence is discussed below:

On March 4, 1981, the licensee conducted RHR system surveillance per OP 4124, RHR and RHR SW System Surveillance, Revision 13. While performing valve operability checks RHR-16A would not open when its control switch was flagged to the open position. MR 81-0279 was issued in conjunction with switching order 81-56 to authroize repairs to the valve operator. Investigation revealed an open contact in the valve interlock circuit which was repaired in approximately one half hour. The RHR-16A valve operability surveillance was subsequently performed satisfactorily. Inspector review of MR 81-0279, switching order 81-56 and OP 4124 surveillance forms 4124.01 and 4124.06 resulted in no identified inadequacies.

The inspector reviewed PRO-6 (potential Reportable Occurrence) issued in accordance with V' AP 0010, Revision 10, Occurrence Reports, which described the event and contains the engineering evaluation of the event approved by the Plant Superintendent.

The inspector had no further questions in this area, no items of noncompliance were identified.

b. Drywell Entry

On March 14, 1981, at 12:15 A.M. a power reduction was initiated to support stability testing, torus testing, and a control rod pattern exchange. At 7·00 A.M. with power at approximately 49%, a drywell entry was made to investigate sources of indicated leakage into the drywell equipment drain sump (DEDS). Indicated leakage into the DEDS had increased from 1.5 GPM to approximately 2.2 GPM during the period of March 1-March 15, 1981, with a corresponding increase in indicated sump temperature on CRP 9-3. At approximately 7:50 A.M. plant personnel were clear of the drywell. The licensee reported that valve RHR V-10-46B, stem packing leakoff isolation valve V-10-193B was closed ½ turn to isolate the source of unidentified leakage. Following shutting of V-193B, the indicated DEDS returned to approximately 1.5 GPM and sump temperature returned to its normal range. The facility operated for the remainder of the inspection period with approximately 1.5 GPM reactor coolant system total leakage and no unidentified system leakage. The limit for unidentified leakage is 5 GPM with a total RCS leakage limit of 25 GPM per TS Section 3.6.c.

The inspector had no further questions in this area. No items of noncompliance were identified.

c. B Recirculation Pump Motor Generator Field Breaker

During routine control room log reviews on March 23, 1981, the inspector noted that problems were experienced with the B Recirc Pump Motor Generator (MG) Set Field Breaker on March 22, 1981. Routine preventive maintenance was in progress to replace the brushes on the pump MG sets. Work on the A pump was completed at 9:30 A.M. with the plant operating at reduced power. With the A pump at minimum speed, the B pump was taken to minimum speed and then tripped off line at 9:40 A.M. by manually opening the pump motor control breaker. Opening of the motor control breaker activates a relay to operate a trip solenoid on the MG Set field breaker to provide for simultaneous interruption of the generator field. The B MG set field breaker failed to open when the motor control breaker was tripped. Control room personnel noted the breaker failure and dispatched personnel to the MG Set area to investigate. Upon arrival, licensee personnel noted that the field breaker was still closed and that the trip coil, which was still energized, was burning up (smoking - no flames were observed). Initial attempts to manually trip the breaker from the front panel were unsuccessful. After pounding on the front panel plate, the breaker internal mechanism became "unstuck", the breaker opened and the trip coil deenergized. The breaker was removed for maintenance and the B recirc pump remained off line for brush replacement. The field breaker and pump were subsequently returned to service at 11:55 A.M. on March 22, 1981.

The B recirc pump and associated MG set breaker and circuitry are not classified as safety related. However, recent installation of the Recirculation Pump Trip (RPT) system has made operation of the MG set field breakers important to safety as a component used to mitigate the consequences of a postulated ATWS event. The RPT trip circuitry, as specified by Technical Specification 3.2.I, will open the recirc pump MG set field breakers upon conditions of reactor vessel lo-lo water level or high pressure. The field breaker is a GE AKF-25 breaker with two (solenoid) trip coils. One trip coil is standard equipment supplied with the breaker and is used for Non-RPT generated trips (e.g. for trips associated with opening the pump motor breaker). The second trip coil was installed as part of the RPT package and is dedicated to the RPT trip circuitry.

Based on a review of GE K 9609 and RPT trip channel logic diagrams (CWD B 191301 sheets 702 and 862) it was determined that none of the RPT actuation circuits contributed to the breaker failure. However, failure of the field breaker to open due to mechanical binding in effect rendered the two instrument trip channels associated with the breaker inoperable. Shutdown of the B recirc pump effected compliance with the TS 3.2.I action statement.

Maintenance work on the breaker included replacement of the trip coil and a check of the internal trip mechanism. No misalignments were observed. A silicone lubrication was applied to the roller pin on the breaker phase contactors. The breaker was subsequently operated manually 8-9 times with no problems noted, re-installed and declared operable. A replacement breaker is on order and will be installed at a subsequent date. Replacement of the B recirc MG set field breaker will be followed by the NRC; this item is considered open pending completion of licensee action (IFI 50-271/81-05-01).

The maintenance history file for the B MG set field breaker was reviewed for the period from April, 1971 to September, 1980. During that period, only one other failure of the breaker was noted. MR 78-602 dated July 3, 1978, was issued to repair the field breaker following a failure to open upon command. The field breaker trip coil was replaced and the B phase roller pin was replaced. The roller pin was found bent and misaligned. No problems were identified with the A recirc pump field breaker based on a review of its maintenance history file.

Based on discussions with licensee personnel, the inspector determined that a 3 year maintenace interval was applied to the breaker. Although the breaker was apparently operable following maintenance on March 22, 1981 and will eventually be replaced, the inspector expressed concern over the reliability of the breaker during the interim period. The licensee stated that consideration would be given to adding the field breakers to the routine preventive maintenance program. Further information would be provided in the Licensee Event Report (LER) submitted for the event.

The inspector had no further comments on this item at the present. This item is open pending submittal of the LER and subsequent review by the NRC (IFI 50-271/81-05-02).

d. Standby Gas Treatment System Testing

Standby Gas Treatment System (SBGTS) Train B was tested in accordance with OP 4601, SBGTS Filter Testing, Revision 7 on March 6, 1981. The test was conducted to verify that the charcoal filter iodine removal efficiency met Technical Specification 3.7.B.2 requirements. The test was declared a failure at 12:45 P.M. on March 6, 1981. Operability testing of SBGTS Train A was completed satisfactorily.

The charcoal beds in the B Train were replaced on March 10, 1981 and the train was subsequently retested satisfactorily on March 12, 1981. Halogenated hydrocarbon removal efficiency was measured to be better than 99.99%. Retest of the B Train was witnessed by the inspector to verify the testing was performed in accordance with plant procedures and to verify the test results were within required limits.

The inspector had no further comments on this item at the present. This item is considered open pending subsequent NRC review of licensee reporting for the event (IFI 50-271/81-05-03).

9. Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee pursuant to Technical Specification 6.7 and Environmental Technical Specification 5.4 were reviewed by the inspector to verify that applicable reporting requirements had been met.

-- VYV 81-26, Monthly Statistical Report, Month of February, 1981, dated March 9, 1981.

-- FVY 81-39, Semiannual Effluent Release Report for the period July through December, 1980, dated March 10, 1981.

No unacceptable conditions were identified.

10. Observations of Physical Security

The inspector made observations, witnessed and/or verified during regular and offshift hours that selected aspects of plant physical security were in accordance with regulatory requirements, the physical security plan and approved procedures.

a. Physical Protection Security Organization

-- observations indicated that a full time member of the security organization with authority to direct physical security actions was present as required.

-- manning of all shifts on various days was observed to be as required.

b. Access Control

Observations of the following items were made:

-- identification, authorization and badging.

-- access control searches, including, when applicable, the use of compensatory measures during periods when equipment was inoperable.

-- personnel escorting and escort/control of private vehicles.

c. Physical Barriers

-- selected barriers in the protected area and vital area were observed and random monitoring of isolation zones was performed. Observation of vehicle searches were made.

-- inspector tours of gate se 1 and 2, the Central and Secondary Alarm Stations were conducted at random periods.

No items of noncompliance were identified.

11. Inspector Actions Based on a Review of NUREG 0737 - TMI Action Plan Requirements

A review was completed during the inspection period of VY implementation of NUREG 0737 - TMI Action Plan requirements. The scope of this review was limited to those items in NUREG 0737 with a specified completion date of on or before January 1, 1981. The review consisted of est - blishing a licensee commitment to fulfill the NUREG 0737 requirement and a followup inspection to determine the status of license implementation. References used for this review were as follows:

(i) NUREG 0737, Clarification of TMI Action Plan Requirements, October 31, 1980

(ii) NRC (Denton) Letter to All Operating Nuclear Power Plants, October 30, 1979

(iii) NUREG 0660, NRC Action Plan Developed as a Result of the TMI-2 Accident, August 1980

(iv) IE Circular 80-02, Nuclear Power Plant Staff Work Hours, February 1, 1980

(v) INPO Guidelines, Nuclear Power Plant Shift Technical Advisor, April 30, 1980

(vi) TI 2515/42-44, TMI Action Plan Inspection Requirements, Revision 2, February 20, 1981

(vii) WVY 80-170, Post TMI Requirements - Implementation Date Commitments, December 15, 1980

(viii) FVY 81-40, Clarification of TMI Requirement Commitments, March 10, 1981

(ix) WVY 80-139, Purge and Vent Valve Operability - Supplemental Information, October 3, 1980

(x) VY Internal Memorandum, Implementation of NUREG 0737, Item I.C.6 - Verification of Correct Performance of Operating Activities, March 9, 1981

(xi) FVY 81-9, Exceptions Taken to Certain Post-TMI Requirements, January 13, 1981

(xii) WVY 80-151, Interim Criteria for Shift Staffing, October 23, 1980

(xiii) NRC Letter to All Operating Plants, January 19, 1981, Information Regarding the Program for Environmental Qualification of Safety Related Electrical Equipment (Generic Letter 81-05)

(xiv) VY 80-176, Response to NUREG 0737 Item I.A.1.1. (4), December 30, 1980

(xv) NRC (Eisenhut) Letter to All Operating Reactors, Interim Criteria for Shift Staffing, July 31, 1980

(xvi) FVY 81-54, NUREG 0737, I.C.6 Guidance on Procedures for Verifying Correct Performance of Operating Activities, March 31, 1981.

In the following listings that follow, "Item Numbers" refer to the NUREG 0737 requirements.

a. Item I.A.1.1 Shift Technical Advisor

(1) Requirements: References (i) and (ii)

Provide on-shift technical advisors to the shift supervisor who have completed all specified training by January 1, 1981. The STA shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in plant design, layout, and analyzed accidents and transients. Pending issuance of formal guidelines by the NRC staff, the education, training and experience requirements specified in sections 5 and 6 of the INPO publication "Nuclear Power Plant Shift Technical Advisor - Recommendations for Position Description, Qualifications, Education and Training" are acceptable to use as interim guidelines for planning the STA program beyond January 1, 1981.

The STA shall be available for duty on each operating shift when the plant is being operated in Modes 1 through 3.

The licensee shall submit to NRC by January 1, 1981, a description of the long term STA program, including selection criteria, qualifications and training programs.

(2) Licensee Commitments: References (vii) and (xiv)

VY placed an interim group of STA's on-shift starting January 1, 1980. Thirteen degreed individuals with plant experience from the plant and corporate staffs fill the STA positions. STA specific training was provided to the group.

Proposed changes to the Technical Specifications that would incorporate the STA position were submitted to the NRC by letters dated September 12, 1980 and October 7, 1980.

A description of the long term STA program was forwarded to NRC:NRR by letter dated December 30, 1980 (Reference (xiv)).

A program was established to hire and train extensively a new group of engineers to ultimately fill the STA role as a full-time job function. This program is presently underway with an estimately completion date of June 1, 1981. The training program has been designed to meet the INPO standards published in May 1980. The interim and long-term programs are operating in parallel to ensure a high degree of participation in this rigorous training program without the interruptions attendent with filling the routine on-shift STA function. At the completion of this training program, the newly trained STA group will be placed on shift to fulfill the STA requirement.

(3) Inspection Findings

Records were reviewed for seven individuals hired during 1980 to fill the permanent STA position (the position is designated as Nuclear Safety Engineer in the VY program). Five of the seven individuals have a bachelors degree in a scientific or engineering discipline. One individual has an associates degree in Applied Mathematics and has been enrolled in a curriculum for a bachelors degree in Mechanical Engineering. A comparison with the guidelines established in Reference (v) shows that the education requirements of section 6.1 have been met or exceeded. A seventh individual has a bachelors degree in a non-scientific or engineering discipline, but has completed additional college level courses in the scientific/engineering field. A comparison with the guidelines established by Reference (v) shows that the education requirements of section 6.1 have been met or exceeded. All seven individuals have had previous work experience in the nuclear industry.

All seven individuals have been enrolled in a VY sponsored training program that began in the Fall of 1980. The course is designed to meet the STA specific training requirements and follows the guidelines of Section 6 of the INPO document. Adherence to the Section 6 guidelines was determined based on a review of training schedules, course outlines provided by GE and YAEC NSD instructors, and training class attendance records. The STA specific training program is scheduled to be completed by June 1, 1981.

Job applications and resumes for all seven individuals were reviewed and compared to the experience requirements of Section 5.2 in Reference (v). All individuals meet the experience requirements to some degree. One individual meets all Section 5.2 requirements. The other designated STAs will "grandfather" into the requirement for having twelve months operating power plant experience at VY subsequent to starting STA shift duty in June, 1981. All should meet the Section 5.2 experience requirements by the end of 1981. The inspector noted that guidelines in Reference (v) require that exceptions to education and experience requirements be reviewed on a case-by-case basis and approved by the Manager of Operations. This action had yet to be taken.

The inspector had no further comments in this area at the present time. This item is unresolved pending: (i) satisfactory completion of the STA training program; (ii) STA assignment to shift duty; and (iii) subsequent review by the NRC (UNR 50-271/81-05-04).

b. Item I.A.1.3.1 Overtime Limits

(1) Requirements: Reference (i) and (iv)

Administrative procedures that limit overtime work hours shall be established by November 1, 1980. The administrative procedures shall set forth a policy, the objective of which is to operate the plant with the required staff and develop working schedules such that the use of overtime is avoided, to the extent practicable, for the plant staff who perform safety related functions.

In the event overtime must be used (excluding extended periods of shutdown) the following overtime restrictions should be followed:

(i) an individual should not be permitted to work more than 12 hours straight (excluding shift turnover time)

(ii) there should be a break of at least 12 hours (including shift turnover time) between work periods

(iii) an individual should not work more than 72 hours in any 7-day period

(iv) an individual should not be required to work more than 14 consecutive days without having 2 consecutive days off.

For circumstances that arise that may require deviations from the above restrictions, such deviations shall be authorized by the plant manager or his deputy in accordance with approved procedures, with appropriate documentation of cause.

If a reactor operator is required to work in excess of 8 continuous hours, he shall be periodically relieved of primary duties at the control board, such that periods of duty at the board do not exceed about 4 hours at a time.

(2) Licensee Commitments: References (vii) and (viii)

By letter dated December 15, 1980, the licensee stated that procedures would be revised to the extent allowed by labor agreements and work schedules to meet the intent of the NRC's guidance. The procedure would be implemented on or before Janaury 1, 1981. By letter dated March 10, 1981, in response to further NRC staff inquiries on this item, the licensee stated that differences between NRC guidance and VY established policy were minor and that no further action is required.

(3) Inspection Findings

Administrative procedure AP 0036, Shift Staffing, Revision 0, was issued on January 8, 1981, to establish requirements on shift staffing and overtime limits. Restrictions on 12-hour work periods and 12-hour break between work periods were adopted verbatim from guidelines (i) and (ii) above. For guidelines (iii), VY adopted an administrative limit that restricts an individual's work hours to be no more than 84 hours in any seven day period. The licensee stated that the NRC guideline of 72 hours in a 7 day-period amounts to an average of 10.3 hours per day, whereas the VY applied restriction amounts to an average of 12 hours per day. For guidelines (iv), VY adopted an administrative limit that requires an individual work no more than 18 consecutive days without having 2 consecutive days off.

For those occasions that arise where work hours in excess of the established administrative limits must be performed, AP 0036 requires that the shift supervisor receive verbal authorization from the Operations Supervisor, who will act as authority for the plant superintendent, to approve the extended hours. The Operations Supervisor will then notify the Plant Superintendent in writing via VYAPF 0036.01 on the next working day to show the cause for the action taken. AP 0036 does not address duty restrictions (i.e., assignment to control board) for those cases where a reactor operator is required to work in excess of 8 continuous hours. AP 0036 defines the minimum shift staffing requirements for both licensed and non-licensed personnel, and applies the overtime limits to the following positions: SS, SCRO, CRO, AO, STA, HP Technicians, security shift supervisor and security guards.

Licensed operator work schedules for period from January 3, 1981 to January 31, 1981 were reviewed to determine the extent of overtime use. Operations personnel are assigned to five 5 member crews that consist of 1 SS, 1 SCRO, 1 CRO and 2 AOs. The five crews are rotated through 3 operating shifts with provisions made for training, vacation and days off. For the period reviewed, overtime was used routinely and most extensively for the CRO position. Based on a review of work assignments over a 41 day period, no instances were identified wherein the AP 0036 overtime limits were exceeded. However, during the 41 day period, work for one individual was scheduled for 76 hours and 80 hours in two separate 7 day periods.

The inspector had no further comments on this item at the present time. However, this item is considered open pending further NRC review of the VY overtime policy and development of a SER on this item (IFI 50-271/81-05-05).

c. Item I.A.1.3.2 Minimum Shift Manning

(1) Requirements: References (i) and (xv)

Implement shift manning requirements for normal operations in accordance with Reference (xv). Staffing requirements shall be completed by July 1, 1982, for operating reactors.

(2) Licensee Commitments: Reference (vii) and (xiv)

VY Committed to implement the minimum shift staffing criteria by July 1, 1982. By letter dated October 23, 1980, VY stated that all adjunct requirements of the NRC July 31, 1980, letter were met, except adjunct requirements d (maintain 1 RO in control room at all times reactor contains fuel) and e (maintain an additional RO onsite at all times reactor is operated). Plans are in progress, including necessary scheduling to accommodate initial licensee operator training, to meet all the revised criteria no later than July 1, 1982.

(3) Inspection Findings

Administrative Procedures AP 0036, Shift Staffing, Revision 0, was issued on January 1, 1981, to address the new staffing requirements to the extent presently practicable. AP 0036 establishes the following requirements:

-- a licensed RO or SRO shall be in the control room (and further, within a defined "Line of sight area") at all times.

-- a licensed SRO shall be inside the control room at all times other than cold shutdown conditions.

-- a shift supervisor, who is also a licensed SRO, shall be onsite at all times the reactor is operating or in startup, but not during cold shutdown conditions.

The inspector noted that the last requirement above does not satisfy adjunct criteria (a) of the NRC's July 31, 1980 letter, which stipulates that the shift supervisor be onsite at all times fuel is in the reactor vessel. The Engineering Support Supervisor noted the inspector's comment and stated that AP 0036, Figure I would be corrected to reflect the adjunct (a) requirements. This item is unresolved pending incorporation of the aforementioned change in AP 0036 and subsequent review by the NRC (UNR 50-271/81-05-06).

Inspector observations of control room/shift manning during routine inspection activities have determined that a SS, SCRO and CRO are normally in the control room and are required to be onsite whenever fuel is in the reactor. The inspector noted also that the licensee has a program in progress to increase the number of licensed reactor operators, which includes five auxiliary operators who recently completed a "Hot License Program". The inspector noted that AP 1000, Refueling, Revision 6, dated September 26, 1980, addresses license requirements for fuel handling activities.

Except as noted above, the inspector had no further comments on this item at the present. This item is considered open pending completion of licensee activities to meet all adjunct requirements by July 1, 1982 and subsequent review by the NRC (IFI 50-271/81-05-07).

d. Item I.A.2.1 Modify Licensed Operator Training Program

(1) Requirements: References (i), (ii) and (iii)

Training programs for licensed operators shall be modified, as required, by August 1, 1980, to provide: (i) training in heat transfer, fluid flow and thermodynamics; (ii) training in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged; and (iii) increased emphasis on reactor and plant transients.

(2) Licensee Commitments: Reference (vii)

The licensee stated by letter dated December 15, 1980, that training programs for licensed operators are in compliance with the requirements.

(3) Inspection Findings

Training schedules, course outlines, lesson plans and training attendance records were reviewed for the 1980 License Program that ran from June 2, 1980, to March 9, 1981. The training subjects listed above were included in the training program. The Operations Training Supervisor stated that the same lesson plans are also used in licensed operator requalification training programs. Training records also showed that the 5 RO candidates spent 12 weeks in training on shift as extra personnel in the control room.

The inspector had no further comments on this item.

e. Item I.C.5 Feedback of Operating Experience

(1) Requirements: References (i), (ii) and (iii)

Procedures shall be prepared to assure that operating information pertinent to plant safety is continually supplied to plant personnel. Procedures governing feedback of operating experience shall be in effect by January 1, 1981.

(2) Licensee Commitments: Reference (vii)

Procedure governing feedback of operating experience to the plant staff will be developed and put into effect by Janaury 1, 1981.

(3) Inspection Findings

Plant administrative procedure AP 0028, Operating Experience Review and Assessment, Revision 0, was issued on December 29, 1980, to satisfy the requirements for this item. In order to facilitate the review process, operating information is divided into two categories. Category A consists of information that may be expected to require a specific response, including NRC bulletins, letters, circulars, information notices, inspection reports, GE SIL's, VY letters, and plant information reports. Category B consists of information that would not normally be expected to require a specific response, including NOMIS, NRC Power Reactor Events, INPO SOE's, GE OER's and Notepad. An Assessment Coordinator (AC) is defined as that member of the Engineering Support staff assigned lead responsibility for implementation, coordination, and performance of AP 0028.

The AC reviews each document received in the A and B categories and assigns responsibility within a plant department for action on the document. For each document assigned, action will be taken to review for applicability to safe operation of VY, identify any items that may require further review, make specific recommendations or request other specific actions, and forward to plant personnel below the Department Head level as required when information in the document is pertinent to the job function. The AC has responsibility to track completion of all items assigned and to conduct annual audits to ensure the objectives of the procedures are met.

Based on a review of AP 0028, discussions with the Engineering Support Supervisor, and a review of information provided to the control room operators, the inspector determined that AP 0028 appeared to address the criteria of Items I.C.5 (1) through I.C.5 (7) of NUREG 0737. However, potential weaknesses in the requirements provided by AP 0028 were noted and discussed with licensee personnel. The inspector's comments included: (i) viability of measures established to avoid duplication of information provided to personnel; and (ii) conduct of annual audits to verify proper implementation of AP 0028 at all levels of personnel, particularly for personnel below the Department Head level. Implementation of AP 0028 will receive subsequent NRC review as part of the routine inspection program.

f. Item I.C.6 Verify Correct Performance of Operating Activities

(1) Requirements: References (i) and (iii)

Plant procedures shall be revised, as necessary, by January 1, 1981, to ensure that an effective system of verifying the correct performance of operating activities is provided.

(2) Licensee Commitments: References (vii) and (xvi)

By letter dated December 15, 1980, VY stated that procedures would be reviewed and revised, as necessary, to provide for independent verification of operational activities whenever operability tests do not otherwise provide this assurance. By letter dated March 31, 1981, VY stated that reviews and implementation of new procedures to meet the intent of Item I.C.6 will be completed by July 1, 1981.

(3) Inspection Findings

An internal memorandum dated March 9, 1981, (reference (x)) documents preliminary VY staff review efforts in the area. The memorandum provided interpretation of the I.C.6 requirements and identified areas to which independent verification would be applied. These areas included local switching control, temporary setpoint changes and certain maintenance/surveillance activities. Areas excluded from the application of independent verification included performance of maintenance, surveillance and operating activities in progress. Also, performance of valve lineups does not require independent verification since it is in itself an independent verification of equipment control procedures.

Licensee review and action on this item is still in progress. Implementation of controls in this area, including the licensee's interpretation of I.C.6 requirements, will be further reviewed by the NRC staff.

This item is unresolved pending completion of the licensee's actions in regard to I.C.6 and subsequent NRC review of the implementation of the I.C.6 requirements (50-271/81-05-08).

g. Item II.D.3 Valve Position Indication

(1) Requirements

The requirements for this item are as listed in NRC Region I Inspection Report 50-271/80-17.

(2) Licensee Commitments: Reference (vii)

Licensee commitments for this item are as listed in NRC Region I Inspection Report 50-271/80-17.

By letter dated December 15, 1980, the licensee provided further information regarding the program to provide seismic qualification for safety and relief valve position indicators.

(3) Inspection Findings

Acoustic accelerometers have been installed on the safety valves. The licensee stated in his December 15, 1980, letter that the program to provide seismic qualification for the devices is being completed in conjunction with the vendor (B&W) and will be completed in the fourth quarter of 1981. NRC follow of this item is being tracked by IFI 50-271/80-02-07. The completed qualification data will be reviewed on a subsequent inspection.

Pressure switches installed on the safety relief valves are presently not qualified. Qualified switches are expected to be received onsite and installed during the second quarter of 1981. This item is considered unresolved pending installation of qualified pressure switches on the SRVs and NRC review of the qualification data (50-271/81-05-09).

h. Item II.E.4.2.5 Containment Isolation Dependability

(1) Requirements: Reference (i)

The containment setpoint pressure that initiates containment isolation for non-essential penetrations must be reduced to the minimum compatible with normal operating conditions. A setpoint pressure 1 psi above the maximum expected containment pressure can be used without further detailed justification.

(2) <u>Licensee Commitments</u>: Reference (vii)

The plant is currently operated with a margin of less than 1 psi between the normal containment operating pressure and the pressure setpoint which initiates containment isolation.

(3) <u>Inspection Findings</u>

Containment isolation pressure setpoint is set, in accordance with the plant Technical Specifications, to less than or equal to 2.5 psig. The normal containment operating pressure is 1.9 psig, or less than 1 psi below the trip setpoint.

The inspector had no further comments on this item.

i. Item II.E.4.2.6 Containment Purge Valves

(1) <u>Requirements</u>: Reference (i)

Containment purge valves that do not meet the operability criteria set forth in Branch Technical Position CSB 6-4 must be sealed closed during operational conditions and verified closed at least once every 31 days. Use of position indication lights in the control room is an acceptable method to verify closure.

(2) <u>Licensee Commitments</u>: Reference (vii) and (ix)

VY submitted information to the NRC:NRR staff which indicated that all purge and vent valves greater than 3 inches in diameter are capable of operating under the most severe design basis accident flow conditions. Although the subject valves would not be sealed closed, to the extent practicable, the purge and exhaust valves would be kept closed in accordance with established administrative controls.

(3) <u>Inspection Findings</u>

The inspector noted by direct observation of valve position indications in the control room that purge and exhaust valves were positioned in accordance with OP 2115, Primary Containment, Revision 9 and MOO Directive 79-4. Under these procedures, purge and exhaust valves are kept closed, except as required to perform Technical Specification surveillance and to maintain drywell-torus differential pressure. Purge and vent valves routinely kept closed are (see reference: Drawing G 191175) SB 16-19-6A, 7C, 7A, 7B, 8, 9, 10, 4, 22A, 11A, 11B and 23. Containment differential pressure is maintained at the Technical Specification required value of 1.7 psi by providing instrument air to the drywell via the drywell pressurization controller, PCV 1-156-3, to establish a positive pressure in the drywell. This flow path is through a 1 inch line with valves PCV 1-156-3, SB 16-19-20 and SB 16-19-22B maintained normally open. The torus is then vented through the Standby Gas Treatment system by venting through containment isolation valves SB 16-19-6B (3 inch) and SB 16-19-6 (8 inch). During discussions with licensee representatives, the inspector noted that the licensee intends to maintain control of containment isolation valves per MOO Directive 79-4 until NRC:NRR reviews and accepts the test data submitted to demonstrate operability of the valves under accident loading conditions. Control of valves under MOO Directive 79-4 will be modified as necessary to support actions in progress to inert the drywell.

The inspector also reviewed data available at the site that demonstrates valve operability under accident flow conditions. The test data is applicable to valves SB 16-19-7A, 7B, 8, 9, 10, 23, 6 and 7. Calculations provided in an Allis-Chalmers report dated March 6, 1980, showed that combined torques due to dynamic accident conditions (pressures up to 60 psig) on valve shafts and discs are in all cases less than the torque applied by the valve motor operators. The calculations were based on testing completed on a 6 inch butterfly valve and reported in A-C VER-0209 dated December 21, 1979. The test conditions included considerations for valve disc position and piping configurations.

The inspector had no further comments on this item.

j. Item II.F.1.A Noble gas Monitor-Interim Category A

(1) Requirements:

Requirements for this item are documented in NRC Region I Inspection Report 50-271/80-17, paragraph 13.d.

(2) Licensee Commitments: Reference (vii)

Licensee commitments and actions on this item are documented in NRC Region I Inspection Report 50-271/80-17, paragraph 13.d.

(3) Inspection Findings

Actions taken to meet the Interim Category A requirements have been completed, as documented in NRC Region I Inspection Report 50-271/80-17. The licensee has committed to completing the long term hardware changes by January 1, 1982.

The inspector had no further comments on this item.

k. Item II.F.1.2.A Iodine/Particulate Sampling-Interim Category A

(1) Requirements:

Requirements for this item are documented in NRC Region I Inspection Report 50-271/80-17, paragraph 13.d.

(2) Licensee Commitments: References (vii) and (xi)

Licensee commitments and actions on this item are documented in NRC Region I Inspection Report 50-271/80-17, paragraph 13.d.

(3) Inspection Findings

Actions taken to meet the Interim Category A requirements have been completed, as documented in NRC Region I Inspection Report 50-271/80-17. VY took exception to the NRC's proposed design basis shielding envelope for assumed I-131 concentrations at the plant stack of 100 micro-Ci/cc, for reasons stated in Reference (xi). Acceptance of the VY position is contingent upon review and approval by the NRC:NRR staff. VY has committed to meeting the January 1, 1982, schedule for additional actions on this item pending timely resolution of their position.

The inspector had no further comments on this item.

l. Item II.K.3.22.A Procedure for Switchover of RCIC Suction

(1) Requirements: Reference (i)

Until such time that the switchover of RCIC system suction from the condensate storage tank to the torus is made an automatic function, plant procedures should provide clear and cogent instructions to plant operators to perform a manual switchover upon reaching a low level in the condensate storage tank.

(2) Licensee Commitments: Reference (vii)

VY reported that existing procedures provided adequate instructions for manual switchover of RCIC suction upon low condensate storage tank level.

(3) Inspection Findings

Plant procedures for operating the RCIC system under startup, normal operating and emergency conditions were reviewed. Only OP 3116, Loss of Coolant Accident, provided instructions on switchover of RCIC suction. OP 3116 directed the CRO to manually switchover RCIC suction upon receipt of annunciators for either low condensate storage tank level or high torus water level. No valve designators or CST/torus level limits were provided. However, RCIC system mimicing on CRP 9-4 provides clear indication of flow paths to the suction of the RCIC pump: (i) one path from the CST through normally open Valve V-13-18; and,(ii) one path from the torus through normally closed valves V-13-39 and V-13-41. Further review of annunciators that would alarm in conjunction with off normal CST/torus level conditions identified two annunciators on CRP 9-3. Alarm response procedures for alarm panel A-1, window B-8 and panel A-3, window B-8 provided potentially conflicting instructions to the operator in regard to RCIC suction switchover.

The above findings were discussed with the Operations Supervisor. DI 81-05 was issued for OP 3116 to clarify the instructions for manual switchover of RCIC suction supply and require that operator actions be taken whenever CST level decreases to 4% or torus level increases to 1.92 feet. The appropriate valve numbers to accomplish the switchover were also referenced in the instructions.

The inspector had no further comment on this item.

m. Item II.K.3.3 Reporting S/RV Failures and Challanges

(1) Requirements: References (ii) and (iii)

Provide a report to the NRC that documents the history of S/RV challanges and failures at the facility.

(2) Licensee Commitments: Reference (vii)

Reporting of safety and relief valve challanges and failures will be included in the 10 CFR 50.59 annual report.

(3) Inspection Findings

The Vermont Yankee 1980 Annual Report (letter FVY 81-48) dated March 23, 1981, reported that there were no challanges to or failures of the safety and relief valves during 1980.

The inspector had no further comment on this item.

n. Item III.D.1.1 Primary Coolant Outside Containment

(1) Requirements:

Requirements for this item are documented in NRC Region I Inspection Report 50-271/80-17, paragraph 13.d.

(2) Licensee Commitments:

Licensee actions on this item are as documented in NRC Region I Inspection Report 50-271/80-17, paragraph 13.d.

(3) Inspection Findings

Unresolved item 80-17-08 was open pending incorporation of RWCU and RECIRC sample systems in the Auxiliary Operators round sheet for the operational leakage surveillance program. This action was accomplished as determined by review of Revision 14 of VYOPF 0150.02 on March 11, 1981. This item is closed.

The inspector had no further comments on this item.

o. Item III.D.3.3 Inplant Radiation Monitoring

(1) Requirements: Reference (i)

Interim requirements for this item are documented in NRC Region I Inspection Report 50-271/80-17, paragraph 13.d. Additionally, Reference (i) required that provisions for measuring iodine concentrations during accident conditions include the use of portable instruments with sample media that will collect iodine selectively over noble gases (e.g. silver zeolite).

(2) Licensee Commitments: Reference (vii) and (xi)

Actions have been completed to provide interim measures to sample and analyze iodines from inplant areas. Portable equipment using sample cartridges containing charcoal are provided, along with procedures governing their use under accident conditions. Analysis instructions require purging of sample cartridges with nitrogen or clean air to remove entrapped noble gases. VY took exception (Reference (xii)) to the requirement to use iodine selective sample media instead of charcoal, in that the charcoal will provide iodine specific adsorption and purging will remove noble gases trapped in the cartridge free air volume.

(3) Inspection Findings

Licensee equipment and procedures for inplant radiation measurements were previously reviewed and found acceptable as documented in NRC Region I Inspection Report 50-271/80-17. Sampling and analysis procedures were again reviewed in light of the requirements for measuring iodines in the presence of noble gases. Procedures OP 3530 and OP 3013 require sample cartridges be purged prior to analyses on either the inplant multi-channel analyses (MCA) or the portable SAM-II units. However, the procedure instructions do not provide specific details necessary to obtain an acceptable purge of noble gases, by either specifying the purge volume required or a purge flow rate over a specified period of time.

This item was discussed with the Chemistry and Health Physics Supervisor. The inspector stated that the NRC staff position was based on the concern that an insufficient purge of noble gases from the sample cartridges could result in an inaccurate determination of the levels of iodine in the measurements, even if the SAM-II units are used. The licensee stated that the sample cartridges would be purged at the same rate as for sample collection - 10 l/min for 1 min. Although no specific experimentation or empirical correlation was done, it was felt, based on previous experiences, that the specified purge rate would achieve a 90% reduction in the noble gas concentration. This reduction would be acceptable for short term measurement results in view of the limitations of the SAM-II units and the availability of backup analysis capability using offsite MCAs. However, the licensee stated that the adequacy of the 10 l/min purge rate would be re-evaluated with additional testing of actual samples. The licensee also stated that the appropriate procedures would be changed to clearly specify the purge requirements.

This item is considered open pending completion of licensee actions and subsequent review by the NRC (IFI 50-271/81-05-10).

12. Inspector Actions Based on Licensee Performance of Stability and Recirculation Pump Trip Test and Torus Response to SRV Discharge Through T-Quenchers

During the period of March 14-March 19, 1981, stability and torus response testing was conducted at Vermont Yankee.

a. The stability and recirculation pump trip test was performed per Special Test Procedure No. 81-01 to obtain data for licensing support and model qualifica .on. The objectives of the stability test were to:

(1) provide test data for qualification of VY stability performance;

(2) provide data for high decay ratio plant operating characteristic assessment;

(3) provide test data for additional stability model qualification at natural circulation, high power conditions where decay ratio is expected to be highest; and

(4) provide support for low pump speed startup.

Stability tests were scheduled to be performed at four points on the minimum speed and natural circulation lines. Pressure perturbations were introduced through the turbine control system; the resulting neutron flux response of the core was monitored and used to determine a core transfer function and finally the decay ratio for that test point. The decay ratio information was utilized to determine the progression to the next test point. The decay ratio was used as a measure of stability, and is defined as a measure of the ratio of one peak to the previous peak in a series of oscillations. Stability decreases as the decay ratio increases. In order to prove that the thermal hydraulic codes used to calculate the decay ratio are correct, it was determined necessary to conduct an actual test that would result in accurate decay ratio measurements.

The recirculation pump trip test was incorporated into the VY stability test program. The objective was to provide data for qualification of operational transient computer codes. Both MG set drive motors were tripped manually and simultaneously from the control room at specified points during the stability test program and plant operation in the natural circulation mode was monitored.

The performance of stability and recirculation pump trip tests required changes to VY Technical Specifications to allow the operation under natural circulation during the tests. The tests also required bypassing of any affected trip functions while the test instrumentation was being installed and removed. The APRM flow biased rod block line and scram and rod block monitoring setting were raised and special MCPR and MAPLHGR limits were used during the test. In a letter from T. A. Ippolito, NRR, to R. L. Smith VYNPC, dated March 11, 1981, the Commission issued Amendment No. 64 to Facility License No. DPR-28 which changed VY TS to permit the performance of stability and recirculation pump trip tests in response to VY submittal dated February 12, 1981.

The SRV torus response test was donducted per Special Test Procedure No. 81-02 to determine the response of the torus and its supports to SRV actuation under cold pipe and hot pipe conditions. The licensee had determined that the projected loads on the torus shell produced by a SRV acuation and predicted by the analytical procedure in GE's Load Definition Report were overly conservative. The GE Load Definition Report is the NRC acceptance criteria for the Mark I Long Term Program with an alternative of performing in-plant SRV tests to generate the SRV pressure forcing function. The Licensee intends that stresses recorded from the tests will be used to verify that torus shell stresses resulting from the SRV loads are sufficiently low such that further modifications to the torus may not be required.

The tests consisted of four sets of SRV actuations; one cold opening followed by one hot opening a minute later repeated three times. Pressure perturbations and torus shell stresses were monitored using instrumentation installed during the 1980 refueling outage.

Prior to issue of STP 81-01 and 81-02, the inspectors conducted a review of the procedures and provided comments to licensee management. All issues were either incorporated into the procedure prior to final approval by plant management or satisfactorily resolved. A review of TS Amendment No. 64 was conducted and licensee conformance to the temporary changes was verified. The inspectors attended licensee briefings conducted for operations department personnel and verified on a sampling basis the installation of test equipment to support STP 81-01 and 81-02.

The inspectors provided in-plant coverage during performance of STP 81-01 and 81-02 the results of which are summarized below:

STP 81-02 was conducted on March 14, 1981. RV2-71C safety relief valve was utilized for four sets of SRV actuations between 8:20 A.M. and 1:00 P.M. with the plant at approximately 45% power. The SRV performed satisfactorily and data was recorded by Teledyne Engineering Services. A visual inspection of the torus indicated that the torus and attachments were secure following SRV testing. The shift supervisor verified that plant conditions stabilized and that RV2-71C properly seated following completion of the test. The newly installed (per NUREG 0578 requirements) SRV open position indicator was observed to actuate when RV2-71C was lifted. Final review of the test data is pending Teledyne Engineering Services evaluation and report issue. Review of STP 81-02 final data will be addressed in a subsequent inspection. (IFI 50-271/81-05-11).

STP 81-01 was conducted during the period of March 14-March 19, 1981, in cooperation with General Electric Company representatives. Reactor pressure, power and other system parameters were recorded by special high speed data logging instrumentation installed for the testing. The instrumentation allowed for rapid determination of reactor system decay ratios following each perturbation. Maximum allowable APRM and oscillatory response limits to pressure perturbations were established for all tests to ensure the plant response to the test remained within acceptable limits. Recirculation system temperature restrictions and vessel stratification restrictions before restarting a recirculation pump at natural circulation conditions were imposed to ensure proper response to the test. All limits and restrictions were verified to be met by operations and test personnel.

Test results from the first two test points (VPT1, 49.5% power and 35% flow; VPT2, 45% power and 36% flow) showed good agreement with the predicted decay ratios. Data from the first two test points were extrapolated to the third test point to provide experimentally modified predictions of reactor stability. Testing at the third major test point, VPT3, was completed at reactor conditions of 51% power and 29% flow. Core flow was close to the natural circulation line with one recirculation pump at minimum speed and with the discharge bypass valve open (main discharge valve closed). The decay ratio was measured to be 0.8.

Flux oscillations at VPT3 became underdamped, but not divergent. The maximum APRM oscillation was $\pm$ 12% peak-to-peak, which was less than the limiting value of $\pm$ 15%. Evaluation of system stability at VPT3 by GE and Test Personnel concluded that no further testing beyond VPT3 need be conducted. System self-excitation was expected to increase at decay ratios greater than 0.8 and further decreases in the measurement signal-to-noise ratio would preclude obtaining meaningful data. Testing was thus terminated after test point VPT3. RPS trip and rod block setpoints were returned to normal settings following restoration of plant conditions.

Test results from the Stability Test were discussed at PORC Meeting No. 81-14 on March 19, 1981. Continued plant operation under existing Technical Specification limits was reviewed in light of the preliminary stability test results and found acceptable.

The inspector had no further comments on this item for the present. No items of noncompliance were identified. Review of STP 81-01 final test results will be addressed in a subsequent inspection (IFI 50-271/81-05-12).

13. Radwaste Transportation Activities

Reviews were conducted during the period of March 25-31, 1981, of licensee activities in the area of packaging radwaste for shipment to an offsite burial ground. Resident Inspector reviews were performed in conjunction with an inspection conducted by a Region-Based Inspector. The purpose, scope and findings of that inspection are documented in NRC Region I Inspection Report 50-271/81-07.

One item reviewed in particular within the area of radwaste packaging activities was the establishment, implementation and maintenance of a Quality Assurance Program in accordance with 10 CFR 71.51. Based on reviews conducted during the period of March 25-17, 1981, and on the result of a meeting held with licensee representatives on March 27, 1981, questions were raised regarding the full implementation of a Quality Assurance Program per 10 CFR 71.51 (d), as applied to the packaging of radwaste and delivery to a carrier for shipment. As a result of the inspection findings, Immediate Action Letter (IAL) 81-17 was issued to the licensee on April 1, 1981. Under the conditions of IAL 81-17 VY will review and evaluate the implementation of the QAP for waste packaging and revise it as necessary to assure quality in the area. The results of the reviews are to be reported in writing to the NRC Region I Office.

Licensee actions in this area will be subject to further NRC review as part of the routine inspection program.

14. PORC Meeting 81-14

The inspector attended Plant Operations Review Committee Meeting No. 81-14 on March 19, 1981, as a non-parcipitant, to observe the committee execute its function. The meeting was held to discuss the results of the recently completed Stability Testing conducted per STP 81-01. The inspector noted that the quorum requirements of Technical Specification 6.2.A.4 were met.

No inadequacies were identified.

15. Unresolved Items

Unresolved items are items about which more information is required to ascertain whether they are acceptable items, items of noncompliance, or deviations. Unresolved items are discussed in Detail 11 of this inspection report.

16. Management Meetings

During the period of the inspection, licensee management was periodically notified of the preliminary findings by the resident inspectors. A summary was also provided at the conclusion of the inspection and prior to report issuance. Additionally, the resident inspectors attended the entrance and exit interviews on March 20, 1981 and April 3, 1981 respectively, conducted by a region-based inspector in regard to an inspection of the licensee's Security and Radwaste Transportation programs.