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

Region I

Report No. 80-08

Docket No. 50-271

License No. DPR-28 Priority -- Category C

Licensee: Vermont Yankee Nuclear Power Corporation

25 Research Drive

Westborough, Massachusetts 01581

Facility Name: Vermont Yankee

Inspection at: Vernon, Vermont

Inspection conducted: June 2 - July 4, 1980

Inspectors: William J. Raymond 8/22/80
W. J. Raymond, Reactor Inspector — date signed

S J Collins 8/22/80
S. J. Collins, Reactor Inspector — date signed

date signed

Approved by: T. T. Martin 9/9/80
T. T. Martin, Chief, Reactor Projects Section No. 3, RO&NS Branch — date signed

Inspection Summary:
Inspection on June 2 - July 4, 1980 (Report No. 50-271/80-08)
Areas Inspected: Routine, unannounced inspection by the Resident inspection staff of: Plant Operations; Safety System Operability Verification; Response to Plant Events; Plant Physical Security; Licensee Periodic Reports; NRC In-Office Review of Licensee Event Reports; Licensee Response to IE Bulletin 80-17; and. Licensee Training Staff Qualifications (TI 2515/36B). The inspection involved 61 inspector-hours onsite by two Resident Inspectors.
Results: No items of noncompliance were identified.

DETAILS

1. Persons Contacted

Mr. R. Branch, Assistant Operations Supervisor
Mr. D. Girroir, Technical Assistant
Mr. M. Lyster, Training Supervisor
Mr. W. Murphy, Plant Superintendent
*Mr. J. Pelletier, Assistant Plant Superintendent
Mr. D. Reid, Engineering Support Supervisor
Mr. R. Sojka, Operations Supervisor
Mr. S. Vekasy, Technical Assistant

The inspectors also interviewed other licensee employees during the inspection, including members of the Operations, Health Physics, Instrument and Control, Maintenance, Security and General Office staffs.

*denotes those present at the exit interviews.

2. Review of Plant Operations

a. Shift Logs and Operating Records

The inspector reviewed, on a sampling basis, the following logs and records for the period of June 2 to July 4, 1980.

-- Shift Supervisor's Log
-- Control Operator's Round Sheet
-- Auxiliary Operator's Round Sheet
-- Night Order Book

The review consisted of verifying adequate management review, correct identification of problem areas, completeness and determination that conditions contrary to Technical Specifications did not exist.

No items of noncompliance were identified.

b. Inspection Tours

The inspectors toured the following accessible plant areas at various times during the inspection:

-- control room
-- all levels of the reactor building, including the corner rooms
-- all levels of the turbine building
-- exterior of the torus
-- diesel generator rooms

-- drywell 238 foot and 251 foot elevations

The following observations and determinations were made:

-- Radiation Protection Controls: step off pads, storage and disposal of protection clothing, and control of high radiation areas were observed in all areas toured. Radiation Work Permit (RWP) controls established for various routine work in the plant were monitored for proper implementation. Standard RWPs numbered 00550, 00555 and 00556, issued 6/12/80 for work inside the drywell were reviewed for adequacy and proper implementation in accordance with AP 0502. Health physics controls in effect for work on valves FW-28B and RHR-46A were observed on 6/12/80 to be in accordance with RWPs 00550 and 00555, respectively.

-- Fluid leaks: all areas toured were examined for evidence of excessive fluid leaks.

-- Control Room Shift Manning: this area was observed to verify compliance with minimum staffing requirements.

-- System Operability: selected valve positions, breaker and equipment start positions were reviewed to verify plant normal operating systems and standby emergency systems were operable in accordance with Technical Specification requirements for the applicable reactor mode. Systems and subsystems observed included the following: diesel generators, offsite transmission circuits, onsite 4 KV distribution system, feedwater/condensate, reactor recirculation, control rod drive, reactor water cleanup, advanced offgas, standby liquid control, low pressure coolant injection, reactor core isolation cooling, core spray, residual heat removal, residual heat removal service water, high presssure coolant injection, service water, drywell purge and ventilation, and, primary containment isolation.

-- Annunciated Conditions: Discussions were held with control room personnel pertaining to the reason for lighted annunciators. The control operator(s) was knowledgeable of the reasons for all lighted annunciators.

-- Plant housekeeping and cleanliness conditions were found to be acceptable.

-- LSSS/LCO: equipment status and operating parameters were observed for conformance with LSSS/LCO requirements. Parameters and equipment monitored included core thermal power; reactor pressure; drywell/torus differential pressure; torus water level and temperature; control rod accumulator pressure and level; liquid poison tank level and boron concentration; condensate storage tank level; reactor coolant system leakage; recirculation loop header equalizer valves; plant gaseous release rates; and, core total peaking factor, minimum critical power ratio and linear heat generation rates.

-- Monitoring Instrumentation: remote (control room) and local monitoring instrumentation was observed to verify its operability and to detect indications of anomalous system operation or conditions. Instrumentation reviewed during this inspection included the nuclear instrumentation; reactor coolant level, pressure and temperature; jet pump; meteorological; reactor vessel steam flow and feedwater flow; containment temperature, pressure, level and differential pressure; process and area radiation monitors; off-gas and stack radiation monitors, recirculation pump pressure, temperature, amperage, flow and seal pressures; drywell floor drain and equipment drain temperature and flow integrators; and, steam leak detection.

-- Shift turnovers of control room operators and supervisors were observed on regular backshifts to verify that transfer of the shift was orderly and that continuity of plant status information was maintained.

-- Portable fire fighting equipment was observed for current inspection stickers and indicated charged within the operable range.

No items of noncompliance were observed and, except as noted below, the inspector had no further comments in this area.

(1) During an inspection tour on July 3, 1980, the inspector noted evidence of minor leakage from CFR hydraulic control unit 22-27, located in the South rack. This observation was reported to the shift supervisor for followup. The inspector observed at a later date that the leak had been repaired. The inspector had no further comments on this item.

(2) During an inspection tour of the diesel generators on July 3, 1980, the inspector noted a lack of status indications for the following: (i) DG 1B local control panel - control power "on"; (ii) DG 1A status light for the 4 KV tie breaker; and (iii) DG 1A 86 lockout relay status. These observations were immediately reported to the shift supervisor and an Auxiliary Operator was dispatched to verify diesel operability. The licensee found that lamps associated with the above circuits had burned out. The light bulbs were replaced and the associated circuitry was tested and found to be satisfactory. The inspector had no further comments on this item.

3. System Operational Safety Verification

A detailed review was conducted of the Standby Liquid Control (SLC) and the High Pressure Coolant Injection (HPCI) Systems during the period July 2-3, 1980, to verify the systems were properly aligned and fully operational in the standby mode. Review of the above systems included the following:

a. Verification that each accessible valve (manual and power operated) in the flow path was in the correct position by either visual observation of the valve or remote position indication. Plant procedures OP 2120 and OP 2114, and drawings G-191169 and G-191171 were used to verify proper HPCI and SLC system lineups, respectively.

b. Verification that power supplies and breakers were properly aligned for components that must actuate upon receipt of an initiation signal.

c. Visual inspection of major components for leakage, proper lubrication, cooling water supply, general condition and other conditions that might prevent fulfillment of their functional requirements.

d. Verification by observation that instrumentation essential to system actuation and performance was operational.

e. Verification of firing circuit continuity for the SLCS squibb valves V11-14A and V11-14B (SLCS only).

f. Verification of acceptable liquid poison tank level and boron concentration (per Technical Specification Figure 3.4.1) and heat tracing control circuitry (SLCS only).

No items of noncompliance were identified.

4. Inspector Followup of Events

The inspectors responded to events that occurred during the inspection to observe/review the licensee's response to the events and to verify continued safe operation of the reactor in accordance with the Technical Specifications and regulatory requirements. Some or all of 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 normal 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 conformance to Technical Specification LCO requirements;

-- determination that root causal factors were identified and that corrective actions, taken or planned, were appropriate to correct the cause;

-- verification that corrective action taken was appropriate to prevent recurrence;

-- determination whether the event involved operation of the facility in a manner which constituted an unreviewed safety question as defined in 10 CFR 50.59 (a) (2), or in such a manner as to represent an unusual hazard to health and safety of the public and environment;

-- determination whether the event involved continued operation of the facility in violation of regulatory requirements or license conditions; and,

-- evaluation of whether applicable reporting requirements were met.

Operational events reviewed during this inspection are discussed below.

a. <u>Feedwater Leakage into Drywell: FW-V-28B</u>

On June 11, 1980, in conjunction with a control rod pattern change, a planned drywell entry was conducted to inspect drywell conditions and investigate suspected reactor coolant system leakage. During the drywell tour, plant operators observed water leaking at about 2 gpm (or less) from the 'B' main feedwater line. Although estimated leakage from the line was within the allowable leak limits of Technical Specification 3.6.C, a plant shutdown was commenced at 4:00 P.M. to investigate and repair the source of the leakage. Plant cold shutdown was achieved at 9:00 P.M. on 6/11 using normal shutdown procedures. Investigation by the licensee revealed that leakage originated from a gasketed mechanical joint of check valve FW-V-28B. Repairs to the feedwater valve were completed, along with a previously known bonnet leak on RHR-V-46A, on June 13, 1980. The inspector reviewed licensee actions taken in response to leak detection, plant shutdown, and repair of the leaky valves and had no further comments on these items.

Further review of the circumstances involved in the leak from valve FW-28B revealed that most leakage from the valve was not collected by the drywell floor drain sump, the normal (primary) leakage detection system for unidentified leakage inside the drywell. Although measured identified and unidentified leakage had increased slightly over the previous two weeks (Identified: from 1.0 gpm to 3.0 gpm, based on pump downs of the drywell equipment drain sump. Unidentified: from 1 gpm to 1.5 gpm, based on pump downs of the drywell floor drain sump). Most of these increases had been attributed to leakage from RHR-V-46A. Based on operator observations of FW-V-28B on 6/11, virtually all (99%) of the leakage from the check valve flowed along the drywell wall, into a drywell/torus vent line, and thence into the suppression chamber, thereby bypassing the drywell drain sumps. In that this flow path bypassed the drywell leakage detection system, it constituted a condition not specifically considered in the plant Safety Analysis Report or the Technical Specifications, and a prompt report was made by the licensee to the NRC in accordance with TS Section 6.7.8.1.i (LER 80-18/1T).

Immediate corrective actions taken by the licensee in preparation for plant startup on 6/13 was to administratively reduce Technical Specification allowable leakage limits. The limit for unidentified leakage was reduced from 5 gpm to 2.5 gpm; the limit for identified leakage was reduced from 25 gpm to 12.5 gpm. These new limits were promulgated to the Operations staff via temporary procedure change to OP 4152, Drywell Equipment and Floor Drain Surveillance; VYAPF 0150.04, Leakage Surveillance log; and, incorporation of the temporary changes along with a copy of LER 80-18/1P in the Night Order Book. Additionally, the oncoming shifts were briefed regarding the potential for leakage to bypass the floor drain sump and were instructed to increase surveillance of changes to torus water level. The inspector verified that the subject instructions were issued. Based on the above, after consultation with NRC Regional staff, the inspector concurred with the return to power operation on 6/13/80, pending further review by the licensee.

Further evaluation by the licensee of the apparent inadequacy of the leakage detection system included consideration for the capability of plant equipment (other than the drywell sumps) to detect drywell leaks, the bases for leakage limits described in the FSAR and Technical Specifications and the adequacy of the new administrative leakage limits. The results of this evaluation were reported in the followup report to LER 80-18/1P and concluded that drywell leakage surveillance should be agumented as indicated below.

(1) The administrative limits of 2.5 gpm unidentified leakage and 12.5 gpm identified leakage would remain in force through continued monitoring of drywell floor and equipment drain sumps per Technical Specification Section 3.6.C. Should either of the above limits be reached, plant procedures require that an orderly shutdown be initiated and the plant placed in cold shutdown within 24 hours. Leakage surveillance using the sumps is conducted once per operating shift on an 8-hour calculational basis.

(2) Monitoring the drywell equipment and floor drain sumps would continue, with an added administrative limit imposed that would initiate an investigation for leakage should a 2 gpm increase above normal levels occur in any eight hour period.

(3) Drywell air temperature from indicator 16-19-45 and RRU 1-4 return air temperature from recorder TR-1-49 would be monitored to detect unexpected increases. Administrative limits are imposed such that any unexpected temperature rise of $6^{\circ}F$ in any 24 hour period would cause an investigation for leakage to be initiated. The basis for the 6° increase in temperature stems from a licensee calculation of the amount of water vapor that will go into the containment atmosphere for an assumed leak rate of 5 gpm. Water flashing to steam would also be condensed by the containment fan cooler units and be collected in the drywell equipment drain sump. For the range of temperatures of importance in considering primary system leakage, 20% of a feedwater system leak would flash to steam (assuming $373^{\circ}F$, 180 psig conditions) and 40% of a reactor coolant leak would flash to steam. Thus, for a 5 gpm feedwater leak, no more than 4 gpm of that leakage would bypass the containment sump, assuming all of the water drained into a vent header.

(4) A torus water volume monitoring program would be established along with investigative action limits. A base line leakage rate (from other interconnecting plant systems) into the torus was developed from torus level data taken over several months. The data, when plotted, showed a constant slope for leakage into the torus of about 2 gpm. Under the monitoring program, an increase in torus level of 257 cubic feet over any 8-hour period (indicative of a 4 gpm leak rate) would initiate an investigation for leakage. In accordance with Technical Specification 3.7.A.1, torus water volume is required to be maintained between 68,000 cubic feet (508,600 gallons) and 70,000 cubic feet (523,600 gallons) and is readily monitored at all times in the control room.

In addition to the above, the containment air monitoring system is available and used to monitor for increases in airborne gaseous and particulate radioactivity inside the drywell. Further licensee evaluation of the need to install physical modifications to prevent bypassing the sumps is in progress, and if deemed necessary, the modifications would be installed prior to startup from the 1980 refueling outage.

The inspector reviewed the licensee's proposed corrective actions, performed independent calculations of limits used for the bases of administrative action levels, reviewed the physical configuration of piping within the drywell in relation to the drywell/torus vent headers, and reviewed the sensitivity of instrumentation available to the control room operator to detect indications of reactor coolant leakage from a variety of sources. The inspector also noted the design basis for the leakage detection system as described in FSAR Section 4.10. System design calculations show that a leak rate of 150 gpm is the minimum required liquid leakage from a pipe crack that is large enough to propagate rapidly. An unidientified liquid leakage limit set at 15 gpm is considered sufficient for leakage detection to allow control operators time for corrective actions before a process barrier is compromised.

Based on the above, the inspector concurred that the augmented leakage surveillance program, together with the drywell equipment and floor drain sumps, is sufficient to detect unidientified leakage within the Technical Specifications limit of 5 gpm in a timely fashion. The inspector verified that procedure changes were made and new leakage surveillance instructions were provided to the control operator by July 3, 1980, in accordance with the following: (i) DI 80-33, dated 7/2/80, as applied to AP 0150, VYAPF 0150.03 and VYAPF 0150.04; (ii) DI 80-34, dated 7/2/80, as applied to OP 2152; and (iii) DI 80-35, dated 7/2/80, as applied to OP 4152.

The inspector had no further comment on the licensee's actions in this area. The results of the licensee evaluations regarding the need for physical modifications will be followed on subsequent inspections (50-271/80-08-01).

b. Recirculation MG Set Trip

On 6/15/80 during escalation to full power, the "B" recirculation MG set tripped off line at 9:27 A.M. with the plant at 70% FP. The loss of one recirculation pump caused reactor coolant flow and reactor power to decrease. No anomalous conditions developed. The trip appeared to occur coincident with an auxiliary operator's (AO) action to reset local relay targets on two generator overcurrent sensing relays. The generator overcurrent and generator neutral overcurrent relay targets were found in the tripped state by the AO prior to the MG set trip and did not trip again as part of the MG set trip.

After stabilizing plant conditions, the licensee's maintenance department inspected the MG set and found no anomalies. The B MG set was restarted at 11:45 A.M. The generator overcurrent and generator neutral overcurrent relay targets tripped, as expected, with the field breaker closed. The relay targets were reset and an MG set trip did not occur. In that the initial problem/condition could not be duplicated and no obvious anomalies were detected with the B MG set, the licensee declared the B recirculation pump operable and resumed escalation to full power. Full power operation with both recirculation pumps operating was subsequently attained without further incident.

The inspector had no further comment on this item. No inadequacies were identified.

c. Turbine Trip - Reactor Trip From 90% FP

At 2:01 P.M. on 6/17/80, the plant tripped while increasing power from 90% FP due to an indicated high level in the moisture separator drain tank. The trip sequence proceeded as follows:

-- a high level developed in the "A" moisture separator drain tank

-- high moisture separator drain tank level initiated an automatic turbine trip to protect the turbine

-- a turbine trip with first stage pressure greater than 30% caused an automatic reactor scram

Control room operator response following the reactor trip was to stabilize plant parameter at the no-load condition using standard reactor trip procedures. Upon the inspector's entrance into the control room at 2:11 P.M., the inspector observed stable plant conditions, an orderly response by control operators and noted the following:

-- Reactor coolant temperatures of 530°F; pressure at 900 psig; both recirculation pumps operating; source and intermediate range nuclear instrumentation on scale; reactor vessel level stable and greater than +30 inches.

-- Turbine bypass valves in operation using the main condenser as a heat sink.

-- No safeguards equipment operating and no conditions that would require ESF equipment operation.

-- No anomalous indications on the containment, reactor building, stack, off-gas or other process/area radiation monitors.

-- Plant house loads supplied via the offsite distribution circuit through the startup transformer. Safeguard system power buses were operable at nominal conditions. The "A" diesel generator was operating; it had been on-line prior to the trip as part of a routine surveillance test and was not required to start during the transient.

-- PCIS isolation (groups 1-3) had been reset to restore bypass valve, reactor water cleanup and reactor building ventilation system operation. The PCIS isolations occurred immediately following the reactor trip due to conditions of reactor vessel water level at +10 inches and main steam line pressure at 850 psig with the mode switch in RUN, and was attributable to the reactor trip and the 100% turbine bypass valve capacity.

The inspector reviewed post trip data from the plant computer and strip charts of reactor vessel level, pressure, feedwater flow, steam flow, turbine first stage pressure, recirculation flow and off-gas radiation levels. Plant response was proper for the initiating event. There were no releases of radioactive material associated with the trip. Hot line notification of the event was made by the Operations Supervisor to the NRC:HQ duty officer pursuant to 10 CFR 50.72 at 4:30 P.M. Except as noted below, no plant system anomalies were identified and the inspector had no further comment in regard to the licensee's response to the transient.

Subsequent licensee investigation of the cause of the turbine trip determined that the high level in the moisture separator drain tank (MSDT) resulted from a combination of a valve malfunction and operator action. The function of the MSDT is to collect condensation from the moisture separators and return the water collected to the feedwater train. MSDT level is controlled within a normal operating band by a drain valve; a backup, emergency drain valve is also provided to maintain drain tank level below a specified limit. Just prior to the turbine trip on 6/15, the MSDT normal drain valve malfunctioned, failed to some mid-position (although its indicated position was full open), and stopped controlling MSDT level. The emergency drain valve opened as required to control level and its open condition was annunciated in the control room. Plant personnel dispatched to investigate the condition observed that the normal drain valve was open and the emergency drain valve apparently malfunctioning. The emergency drain valve was cycled to trouble shoot its operation. Closing the valve caused the MSDT high level turbine trip setpoint to be reached. Further investigation of the operation of both the normal and emergency drain valves revealed that the normal drain valve positioning controller had malfunctioned and that the emergency drain valve had functioned properly. The normal drain valve positioner was repaired and tested prior to the return of plant operations to power.

During the review of plant system status following the trip to verify all systems had responded as required, the licensee noted that valve FSO-109-76A failed to close as required upon receipt of a PCIS group 3 insolation signal. Valve FSO-109-76A is one of two series outboard isolation valves in the containment air sample system. The valves are located in a one-half inch diameter line on the discharge side of the radiation monitor. Companion valve FSO-109-76B did close as required so that isolation of the sample line would have occurred had isolation been necessary. Failure of one of two valves to close as required constituted a 30-day reportable event under the Technical Specifications and LER 80-20/3L was submitted to the NRC.

The inspector was notified of the valve malfunction upon its discovery. Immediate investigation of valve operability showed that the valve could be closed (and cycled) using the remote control switch on the control board. A maintenance request was issued to further investigate valve operation. Upon disassembly, the licensee found that dirt had become lodged on the valve internals and caused the valve to sometimes stick. The valve internals were cleaned, the valve was re-assembled and returned to an operable status prior to plant startup on 6/15/80.

The inspector had no further comment on this item. No inadequacies were identified in the licensee's response to this event.

5. 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

-- Observation and personnel interviews 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. 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.

-- Alterations to the gatehouse #2 structure and established compensatory controls were monitored.

c. Access Control

Observations of the following items were made:

-- Identification, authorization and badging.

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

-- Escorting.

No items of noncompliance were observed.

6. Review of Periodic Reports

The periodic reports listed below were reviewed to verify that reporting requirements have been met.

-- Monthly Operating Reports for the months of April, May, June and July, 1980.

-- 1979 Annual Operating Report.

No unacceptable conditions were identified.

7. In-Office Review of Licensee Event Reports

The licensee event reports (LERs) listed below were reviewed in the NRC Resident/Regional Office. The reports were reviewed to determine whether: the information provided was clear in the description of the event and identification of safety significance; the event cause was identified and corrective actions taken (or planned) were appropriate; the report satisfied requirements with respect to information provided and timeliness of submittal; and, on-site followup was warranted. Those reports annotated with an asterisk (*) concern events that occurred when the inspector was onsite and inspector review/evaluation of the event is documented elsewhere, in this or other inspection reports.

LERs 79-26, 79-29, 79-30, 79-31, 79-32, 79-33, 79-34, 79-35, 79-36, 80-01, 80-02, 80-04, 80-08, 80-13, 80-14, 80-15, 80-16, 80-18*, 80-19* and 80-20.

No items of noncompliance were identified.

8. IEB 80-17: BWR Scram System

On 7/3/80, IE Bulletin 80-17 was issued to all BWR licensees, which required certain actions be taken in response to concerns raised over the failure of 76 out of 185 control rods to scram at the Browns Ferry Unit 3 Nuclear Plant. The bulletin required both short-term and long-term investigative actions be taken. The following specific actions were required to be completed at the Vermont Yankee Nuclear Plant by July 6, 1980:

-- Perform surveillance tests to verify that there is no significant amount of water in the scram discharge volume (SDV) and associated piping; that the SDV vent valves are operable; and, that the vent system is free of obstructions.

The licensee developed procedures and completed testing during the 7/3-7/6 period to satisfy the aforementioned requirements. Testing of valves 3-

32A, 3-32B and 3-33 was completed on 7/4/80 by cycling the valves using the control switch on CRP 9-5, while individuals stationed at the valves confirmed the valves stroked through full travel. Vent lines servicing both the North and South hydraulic control unit (HCU) headers were verified to be free of obstructions on 7/4/80, by opening the lines upstream of valve V3-32A (V3-32B), pouring in 6 gallons of water, and verifying the vent lines drained rapidly to the HCU headers.

A special ultrasonic test (UT) procedure was developed on site to detect accumulation of water in the HCU headers. A mockup of the header piping was used to demonstrate the validity of the UT measurement technique and to calibrate the UT equipment for each header measurement taken. Five individuals from the licensee's Maintenance Department were trained by a Level III UT inspector on the methodology and equipment used to monitor for water in the SDV piping. The inspector witnessed portions of both the calibration of UT equipment and measurements taken at three locations on each SDV header during the period of 7/4-6/80. No water accumulation was found during any of the measurements.

The inspector had no further comments on this item at the present. Further actions taken by the licensee in response to IEB 80-17 will be followed during subsequent inspections (50-271/80-08-02).

9. Training Staff Qualifications

The inspector met with licensee personnel responsible for implementing the requirements of the March 28, 1980, letter from Harold R. Denton of NRR to all licensees. The purpose of the inspection was to verify that applications for Senior Reactor Operator (SRO) license examinations have been or will be submitted by August 1, 1980, for licensee training staff members who teach specified courses.

The inspector verified that the licensee had received the subject letter of March 28, 1980 and intends to comply with its requirements. The inspector verified by record review that the licensee instructors currently involved in training on systems, integrated response, transients, and simulator responses hold an SRO license. The licensee stated that the job descriptions of the remaining members of the training staff prevent them from conducting training in the course areas of concern, and there are no plans to submit license applications for these individuals.

The inspector had no further questions in this area.

10. Exit Interview

Management meetings were held with licensee personnel at various times during the inspection. The inspection purpose, scope and findings were discussed as they appear in the details of this report.