Enclosure 2

U.S. Nuclear Regulatory Commission
Region I

Report No. 95-25

Docket No. 50-271

Licensee No. DPR-28

Licensee: Vermont Yankee Nuclear Power Corporation
RD 5, Box 169
Ferry Road
Brattleboro, VT 05301

Facility: Vermont Yankee Nuclear Power Station
Vernon, Vermont

Inspection Period: November 7 - December 31, 1995

Inspectors: William A. Cook, Senior Resident Inspector
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Approved by: Richard J Conte 2/14/96
Richard J. Conte Date
Chief, Reactor Projects Branch 5

Scope: Station activities inspected by the resident staff this period included Operations, Maintenance, Engineering, Plant Support, and Safety Assessment and Quality Verification. Backshift and "deep" backshift including weekend activities amounting to 21.5 hours were performed on November 7, 8, 9, 10, 11 and December 4, 6, 7. 8. and 21. Interviews and discussions were conducted with members of Vermont Yankee management and staff as necessary to support this inspection.

Findings: An overall assessment of performance during this period is summarized in the Executive Summary. Inspector review of the Vermont Yankee staff's evaluation and root cause of the December 8 reactor scram is being tracked as an unresolved item (URI 95-25-01). NRC staff review is planned for Vermont Yankee's HPCI operability determination with HPCI pump suction aligned to the suppression chamber (IFI 95-25-02). NRC staff review of VY's responses to Bulletin 95-02 and surveillance of ECCS suction strainer performance is planned (IFI 95-25-03). Resolution of a Technical Specification error involving the specified test gas mixture for advanced offgas system hydrogen monitor calibrations is an unresolved item (URI 95-25-04). Further inspector review of single failure and primary containment integrity concerns involving the HPCI system suction valves logic design is an unresolved item (URI 95-25-05). NRC review of system modification impact and associated protective tagging controls is unresolved (URI 95-25-06). Unresolved item (URI 94-13-02) regarding the level of quality assurance applied to non-nuclear safety components that retain reactor coolant system pressure was closed. Violation (VIO 94-13-02) was updated to reflect recent inspection observations of the PORC. Enforcement discretion was applied to the violations described in LERs 95-01, 95-02, 95-18, and their associate supplements.

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Note: Procedures from NRC Inspection Manual Chapter 2515, "Operating Reactor Inspection Program" which were used as inspection guidance are parenthetically listed for each applicable report section.

REPORT DETAILS FOR RESIDENT INSPECTION
No. 50-271/95-25

1.0 SUMMARY OF FACILITY ACTIVITIES

Vermont Yankee Nuclear Power Station (VY) operated at 100 percent rated reactor power throughout this inspection period until December 8 when an automatic reactor scram occurred due to a main turbine trip due to high reactor water level. On December 10, following repairs and VY's post-trip review, the plant was returned to full power operation. Minor reactor power changes were also made this period to support surveillance and single rod scram testing.

During the week of November 13, a region based specialist inspector conducted a routine inspection of VY's Security Program. Inspector findings and conclusions are enclosed.

This period, VY reorganized their Engineering Department into six major functional areas reporting to a single Vice President Engineering. The functional areas include: Project Engineering; Performance Engineering; Technical Support; Nuclear Services; and, Design Engineering. The latter two departments previously reported and were part of the Yankee Nuclear Services Division (YNSD) at Yankee Atomic Electric Company (YAEC). As stated in VY information the reorganization was undertaken, in part, to combine VY and YNSD engineering resources, to improve the organization's efficiency, to reduce the bureaucracy, and to help foster the implementation of the "system engineering" concept.

The Reactor and Computer Engineering Department was also reorganized effectively splitting the functional disciplines into two separate groups. However, both the Reactor Engineering Department and Computer Engineering Group continue to report to the Technical Services Superintendent.

2.0 OPERATIONS (71707, 71714)

2.1 Operational Safety Verification

The inspectors verified adequate staffing, adherence to procedures and Technical Specification (TS) limiting conditions for operation (LCO), operability of protective systems, status of control room annunciators, and availability of emergency core cooling systems. Plant tours confirmed that control panel indications accurately represented safety system line-ups. Safety tagouts properly isolated equipment for maintenance.

2.2 (Open) URI 95-25-01: Reactor Scram

On December 8, at 11:14 a.m., the reactor scrammed from 79 percent power due to a turbine trip on high reactor vessel level. The reactor vessel level transient resulted from troubleshooting the "A" feedwater regulating valve (FRV). Earlier in the morning, reactor power was being reduced via recirculation flow to support removal of the "A" FRV from service to further troubleshoot observed oscillations of the FRV detected by the operations staff. When reactor power was approximately 80 percent, severe feedwater piping vibration and "A" FRV stem cycling were witnessed locally. A licensed operator at the FRV, quickly took local manual control of the valve by inserting a tapered stem locking pin. The feedwater pipe vibration stopped. Reactor vessel water level was maintained within the normal control band throughout this transient.

Operating procedures specify that an operator be stationed locally in direct communications with the control room while a FRV is in local manual control. This condition is specified to ensure proper manual control of the FRV should a transient occur necessitating a reactor vessel level change beyond the capacity of the "B" FRV automatic level control capability. This action was implemented, however, due to a severe pipe shake discussed above, asbestos laden dust was deposited throughout the feedpump room and the auxiliary operator assigned the local FRV control duties was temporarily stationed in the turbine lube oil room adjacent to the feedpump room. The decision to locate the operator in an adjacent room was because he lacked adequate asbestos worker training and qualifications to remain in the feedpump room while cleanup was in progress.

In the turbine lube oil room, the auxiliary operator was available to respond, but not in direct line of sight (behind a closed door) with the "A" FRV. Subsequently, due to normal flow induced piping vibration and because the tapered stem locking pin was not fully engaged (due to the difficulty encountered in pinning the cycling FRV stem), the locking pin vibrated out and the resultant unregulated feedwater flow caused reactor vessel level to rise and the subsequent turbine trip/reactor scram before manual action could be initiated. The inspector notes that during the intervening time that the FRV was pinned and it vibrated out, crews were cleaning up the asbestos dust and the plant staff was evaluating alternatives to reducing reactor power to remove the "A" FRV from service. As discussed in detail in section 2.2.1 below, reactor conditions were quickly stabilized and the reactor mode maintained in Hot Standby while the necessary repairs were made. FRV troubleshooting is discussed in Section 3.1.2.

At the end of the inspection period, the VY staff had not completed their evaluation and root cause analysis for this reactor scram. Preliminarily the inspector noted that the stem locking pin could have been better monitored and potentially prevented from vibrating out of the stem locking device. Pending inspector review of the licensee's evaluation and root cause analysis of this reactor scram, this event is unresolved **(URI 95-25-01)**.

2.2.1 Scram Recovery: Actions and Performance

Control room operator (CRO) actions and performance in response to the transient effectively resulted in the safe reactor power transition to a hot standby condition. The inspector observed prompt and accurate communications regarding the status of all control rods, reactor power, level, pressure, and status of other safety systems. Clear instructions were given to the reactor operators (ROs) regarding reactor pressure control using the turbine bypass valves and level control using a combination of reactor water cleanup and the feedwater and condensate systems. Approximately one minute following the scram, plant conditions were stable and well controlled.

Within two minutes, post-scram recovery actions were implemented. The emergency operating procedures were entered for the scram and for the assessment of plant parameters. Turbine control and reactor shutdown operating procedures were implemented in parallel with their investigation of the cause of the scram (reference Section 2.2). Fifteen minutes after the scram, the scram was reset and a control room brief was held. During the brief, the Shift Supervisor (SS) reviewed plant conditions, the cause of the scram, procedures in use, discussed plant support activities, and clearly articulated plans to achieve and maintain a hot shutdown condition. The inspector also observed two subsequent briefs conducted by the SS.

Inter-departmental support following the scram contributed to a prompt assessment of plant conditions. An off-shift SS led, coordinated, and reported activities within the feed pump room and helped stabilize reactor water level control. The Reactor Engineering Department retrieved and evaluated computer generated scram times to assess control rod performance (reference Section 4.1). The on-shift SS effectively augmented his staff with off-shift operators and shift engineers to assist in recovery actions. The plant operations management was cognizant of plant conditions, observed post-scram activities, and provided oversight of SS decisions involving reactor safety.

The inspector concluded that following the reactor scram the plant systems were appropriately operated through a combination of proper and timely actions by the CROs, implementation of procedures, strong inter-departmental support, and management oversight. The assessment of plant conditions was thorough and focused on key reactor parameters such as scram time data and reactor water level.

2.3 Cold Weather Preparations

The inspectors reviewed VY's preparation for cold weather to assess whether reasonable actions have been implemented to preclude temperature related component and system failures as noted in past years. VY prepared systems for cold weather in accordance with OP 2196, Preparation for Cold Weather Operations.

The inspectors conducted system walk-downs, reviewed OP 2196, and identified no concerns with VY's preparation for cold weather. The procedure was implemented in advance of seasonal cold temperatures. Management reviews were routinely conducted to assess the status of heating systems for the emergency diesel generator (EDG) fuel oil tank and other plant systems. An engineering evaluation was conducted to assess the performance of diaphragms located within certain reactor building isolation dampers and the chemistry staff closely monitored the pour point of EDG fuel oil. Winter preventive maintenance was conducted on the cooling towers, the intake ventilation system was aligned for the winter, and heat trace circuits were energized. VY identified freezing of the service water chemical treatment pipe and a level transmitter for the demineralizer storage water tank. None of the problems mentioned above adversely affected plant operation.

The inspector independently confirmed the completion of a selected number of

OP 2196 requirements. Inspector walk-down of the intake structure, EDG fuel oil tank, condensate storage water tank (CST), and the heating and ventilation room with a thermography camera identified no concerns. Insulation was intact and dead-leg piping runs were confirmed to be warmer than 32 degrees F. The general area temperatures were warm and maintained by heating units. No standing liquid was observed adjacent to the CST and EDG fuel oil storage tanks. Access to the travelling screen and intake gates was unfettered by ice and snow. An inspection of the alternate cooling tower confirmed sufficient de-icing water flow to prevent freezing and access to outdoor fire fighting equipment was unfettered by ice and snow.

2.4 (Open) IFI 95-25-02: High Pressure Coolant Injection Operation and Testing

The inspector reviewed the operation and testing of the high pressure coolant injection (HPCI) system with particular emphasis on HPCI operation with its pump suction aligned to the suppression chamber (SC). As described in Chapter 6 of the Final Safety Analysis Report (FSAR), HPCI pump suction is normally aligned to the CST and will automatically transfer to the SC on low CST level. This design feature can be implemented manually via HPCI operating procedure OP 2120, High Pressure Coolant Injection System, and during HPCI surveillance procedure OP 4120, HPCI Surveillance. A manual transfer is allowable if torus water level approaches 11.92 feet and if SC water temperature is less than 140 degrees F. An automatic transfer occurs if CST level falls to 4 percent (approximately 75,000 gallons). Based on VY procedures, HPCI is operable irrespective of HPCI pump suction alignment. The term operable, as used here, is defined as the capacity for HPCI to provide 4250 gpm to the reactor during post-accident conditions.

The inspector reviewed pre- and post-startup (circa 1971) and surveillance testing and noted that (unlike the HPCI pump suction aligned to the CST) the HPCI system has never been demonstrated operational with its pump suction aligned to the SC. A calculation or evaluation demonstrating operability of this flow path was also not found. A startup test was performed in 1971 to verify an open SC-to-SC flow path, however, this was conducted at one-half turbine speed, more indicative of a cleanliness flush, and not demonstrative of HPCI flow capability to the reactor during post-accident conditions. Inservice inspection and testing of the suction piping and valves has been performed and provides additional confidence that these components are materially sound and operable. The inspector also noted that based on the surveillance and pre-startup testing of the reactor core isolation cooling (RCIC) system, a similar condition may exist.

Based upon the above observations and discussions with station management, VY wrote an Event Report (ER) to initiate a review to ascertain whether a calculation or evaluation exists that would further support HPCI operability when aligned to the SC. At the conclusion of the inspection period, the inspector had identified no immediate concerns regarding HPCI operability. Pre-startup testing, inservice inspection and testing, full flow testing to the CST, and adequate net positive suction head to the HPCI booster pump provide reasonable confidence that HPCI can perform its safety function with its suction aligned to the SC. The NRC staff plans further review of this issue (IFI 95-25-02).

3.0 MAINTENANCE (62703, 61726)

3.1 Maintenance Activities

The inspectors observed selected maintenance on safety-related equipment to determine whether these activities were effectively conducted in accordance with VY TS, and administrative controls (Procedure AP-0021 and AP-4000) using approved procedures, safe tag-out practices and appropriate industry codes and standards. Interviews were conducted with the cognizant engineers and maintenance personnel and vendor equipment manuals were reviewed. The inspectors reviewed corrective maintenance on the 1T and 79-40 345 kV switchyard circuit breakers, repairs to the alternate cooling tower cell 2-1 (reference Section 3.2), and the failure of the downstream river water sampler. These activities were conducted with proper safety tag-outs and received appropriate management reviews.

The problems associated with the 345 kV switchyard circuit breakers were caused by cold temperatures. Specifically, the 1T breaker inadvertently opened on low system air pressure and the 79-40 breaker routinely alarmed due to low sodium hexa-floride (SF6) gas pressure. The 79-40 breaker problems have occurred during previous winters and have not been effectively resolved to preclude recurrence. To compensate, the VY staff has instituted enhanced monitoring of these breakers. These breakers are under the control of VelCo (the power distribution and transmission authority) for major maintenance activities.

The failure of downstream river water sampler was also recurrent. This sampler generally fails when the Connecticut River water level increases during Spring and/or Fall run-offs. Also, the design of this sampler tends to entrain river silt in the process line degrading the operation of the sample pump. With the sampler out-of-service, TS radiological sampling requirements were satisfied by daily grab samples. The inspector verified that an ER was initiated to assess this condition.

3.1.1 Alternate Cooling Tower Structural Failure

Twice a year VY inspects, performs preventive maintenance, and repairs identified deficiencies of the forced-air cooling towers. As previously documented in NRC Inspection Report 95-17, some timbers that make up the lattice structure of the towers have failed or degraded to the point that replacement was necessary. These prior problems were limited to the non-safety related, non-seismic section of the cooling tower system. This period, VY identified that three vertical supports and one horizontal beam had failed in cell 2-1. This cell is safety related and seismically qualified and acts as the ultimate heat sink should the cooling capacity of the Connecticut River be significantly reduced.

Vermont Yankee immediately commenced repair of the identified problems and initiated an ER to ascertain whether problems exist with the design, maintenance, and/or inspection of the entire cooling tower system. VY entered the applicable seven-day LCO during this maintenance. VY also determined that they have adequate confidence that cell 2-1 would remain operable until the next scheduled inspection (Spring of 1996). The inspectors had no concerns regarding VY actions.

3.1.2 Feedwater Regulation Valve Troubleshooting

As previously discussed in Section 2.2, activities related to the downpower to troubleshoot the "A" FRV lead to the December 8 reactor scram. The inspector was aware of earlier attempts (prior to December 8) to diagnose the minor oscillation observed in the "A" FRV by the Instrumentation and Controls (I&C) Department. This diagnostic troubleshooting involved pinning the valve locally (per procedure) and cycling the controller to evaluate input and output response. The I&C staff employed a vendor to assist in this type of troubleshooting and was still awaiting the results of this diagnostic review when the December 8 downpower to remove the FRV from service was conducted.

Subsequent to the December 8 reactor scram (the vendor had completed the data analysis and had attempted to communicate the results the day of the scram), the VY I&C staff received the results which indicated that the FRV controller was functioning properly and that the oscillation problem was associated with the mechanical operation of the valve or valve internals. Vermont Yankee decided to proceed with the reactor downpower maneuver without the "A" FRV pinned and under local manual control, and without a status report on the subject data analysis. This action reflected weak oversight of the problem by maintenance management.

3.2 Surveillance Activities

The inspector reviewed procedures, witnessed testing in-progress, and reviewed completed surveillance record packages. The surveillance tests which follow were reviewed and were found effective with respect to meeting the safety objectives of the surveillance program. The inspector observed that all tests were performed by qualified and knowledgeable personnel, and in accordance with VY TS, and administrative controls (Procedure AP-4000), using TS approved procedures.

- OP-4400, Calibration of the Average Power Range Monitoring System to Core Thermal Power, performed on 11/8/95
- AP 0164, Operating Department Inservice Testing, performed on 11/8/95
- OP-4115, Primary Containment and Surveillance
- OP-4152, Equipment and Floor Drain Sump and Totalizer Surveillance
- OP-4113, Main and Auxiliary Steam System Surveillance, performed on 11/7/95
- OP-2403, Control Rod Sequence Exchange With the Reactor On-Line, performed on 11/7/95
- OP-4424, Control Rod Scram Testing and Data Reduction, performed on 11/7/95

3.2.1 Single Rod Scram Time Testing

On November 7, VY conducted TS required single rod scram testing of 45 control rods. The notch 46 drop-out time for the 45 rods tested had increased from a beginning-of-cycle (BOC) average of 0.317 seconds to 0.347 seconds. With the 45 tested rod times averaged in to the remaining 44 rods (tested at BOC) the core-wide average for notch 46 drop-out increased from 0.317 to 0.333 seconds. The TS 3.3.C.1.1 core-wide average for notch 46 is 0.358 seconds.

VY management and the Plant Operations Review Committee (PORC) reviewed this scram time degradation and determined that the plant could continue operation for a limited period of time, however, contingencies would need to be immediately initiated. The licensee extrapolated the degradation and determined that the core-wide average would approach the TS limit in January 1996. In the interim, reviews were conducted to assess control rod drive (CRD) maintenance, the scram time data retrieval system, reactor protection system voltage applied to the scram solenoid pilot valves (SSPVs), CRD air quality, and hydraulic control unit pressures. An industry search was initiated to determine whether other nuclear utilities experienced similar time degradation. Discussions with General Electric (GE) and Automatic Switch Company (ASCo), supplier of the SSPVs, were initiated.

On November 9, five control rods were scrammed for troubleshooting purposes. Results were similar, the notch 46 drop-out time was approximately 30 milliseconds slow. No problems were identified with the any of the supporting systems. On November 15, the SSPV assembly for CRD 42-23 was removed and bench tested. Results indicated that the cause of the slowed scram times was SSPV degradation. The rod 42-23 SSPV assembly slowed from 0.047 to 0.107 seconds. Two additional sets of SSPVs were removed and troubleshooting specific to SSPVs was commenced. On November 21, VY determined that the SSPV diaphragms experienced elastic deformation while in use. In particular, the VITON elastomer diaphragm (ASCo model number HV-266000-2J) chemically reacted with the SSPV end cap resulting in the diaphragm "sticking" to the end cap. The licensee also determined that the '118' SSPV was the primary contributor to the slowed scram times. Preparations to replace the diaphragms and end-caps began. The inspector noted that if the diaphragms stick to the end-cap, a higher differential pressure (hence more time) would be needed to cause the diaphragm to flex and vent air off the scram valves.

On December 8, a reactor scram occurred (reference Section 2.2) and the core-wide notch 46 drop-out time was 0.355 seconds, representing a slightly quicker degradation rate than previously assumed. VY management decided to replace the '118' end caps, o-rings, and diaphragms; the '117' SSPVs were not changed due to the unavailability of parts. On December 10, the '118' replacements were completed and single rod scrams resulted in a core-average notch 46 drop-out of 0.329 seconds. The plant was returned to full power.

In summary, VY aggressively pursued this problem, informed other nuclear power plants of this generic concern, and pro-actively established an accelerated single rod scram testing schedule to monitor for further degradation. Additional end-caps, o-rings, and diaphragms were being procured to replace the '117' SSPVs. A few negative aspects of VY's approach to resolve this problem were noted, such as the slow development of a statistically representative sample size for the assessment of core-wide scram time performance and a weak equivalency evaluation for the new diaphragm end-caps. These aspects were minor and did not significantly detract from the overall good safety focus demonstrated by the plant staff.

3.2.2 Residual Heat Removal Suction Strainer Special Test

NRC Bulletin 95-02, Unexpected Clogging of a Residual Heat Removal (RHR) Pump Strainer While Operating in Suppression Pool Cooling Mode, alerts licensees to a recent industry event and requests, in part, that licensees show by demonstration and administrative controls that the RHR system would remain operable during post-accident SC cooling operations. The inspectors reviewed VY's response to Bulletin 95-02 and evaluated the conduct of VY special test procedure (STP) 95-12, RHR Suction Strainer Special Test, to ascertain whether VY adequately addressed the generic safety concern described in the bulletin.

VY letter dated November 16 entitled, 30-Day Response to NRC Bulletin 95-02, accurately represented the actions performed and credit taken by VY in their assessment of Bulletin 95-02. The inspectors independently confirmed by inspection that the SC was cleaned during the 1995 refueling outage; foreign material exclusion controls and conduct of primary containment close-out inspections for the drywell and SC have been adequate; and, the emergency core cooling system (ECCS) pump suction strainers were appropriately sized. By letter dated December 18, VY reported the results of their testing and conclusion that no suction strainer clogging occurred during the conduct of the testing. The inspectors confirmed that these results were also accurate. Further NRC staff review of the licensee's response is planned.

The inspectors reviewed STP 95-12, observed portions of the test, and concluded that the test was conducted safely. Test coordination was provided by a SS and management oversight of the test was provided by the Assistant Operations Manager. The pre-test brief focused on command and control, communications, acceptance criteria, and the sequence of events. Particular emphasis was placed on test termination criteria and the recognition of strainer clogging and pump problems.

STP 95-12 was reviewed by the Quality Assurance group, approved by the Manager of Operations, and reviewed by a subcommittee of the Nuclear Safety Audit and Review Committee. Procedure steps were succinct and clearly written. Single and dual verifications were used throughout the STP. Appropriate instructions and descriptive drawings were provided for the installation and control of temporary pressure instruments. Test acceptance criteria were selected to provide margin to any adverse condition caused by the testing and were reasonably based on the accuracy of test instruments. The 10CFR50.59 safety evaluation supporting STP 95-12 was complete and sufficiently justified VY's determination that no unreviewed safety question existed for the conduct of this test. Overall the ECCS suction strainer test was thoroughly pre-planned and evaluated. The related procedure and implementation reflected a well controlled evolution with enhanced management oversight.

3.2.3 (Open) IFI 95-25-03): Pump Suction Pressure Evaluation During Surveillance

The inspector evaluated pump performance data obtained during the surveillance testing of core spray (CS), high pressure coolant injection (HPCI), reactor core isolation (RCIC), and RHR pumps and noted the following. First, an acceptance criteria of >0 psig for pump suction was established for the CS, HPCI, and RCIC pumps, however, no criteria had been established for the RHR pumps. Second, pump suction pressures are always greater than 0 psig (during standby or pump operation) because of system orientation and hydraulic performance; and, therefore, of little value for the measurement of system performance.

The inspector noted that a more representative operational limit for pump suction pressures could be based on a deviation from a normally expected value. For suction pressures, this type of acceptance criteria could be indicative of a loss of net positive suction due to strainer clogging, as represented in NRC Bulletin 95-02. As described in Section 3.2.2, this type of acceptance criteria was used in combination with high accuracy pressure gages.

These observations were discussed with the Operations Department In-Service Test (IST) Coordinator. At that time, the inspector was informed that an internal VY commitment item was still open regarding possible system improvements to enhance the monitoring of ECCS suction pressures. The inspector was also informed that there was no readily available justification for the 0 psig or greater acceptance criteria and that the installed pressure gages were of insufficient accuracy to effectively monitor suction strainer clogging (the gauges are adequate for normal system operation and test). These pressure gauges are original plant equipment and design.

In summary, VY's testing of ECCS pumps met regulatory requirements, however, the testing methodology and procedure acceptance criteria during quarterly surveillance testing provided limited value for the evaluation of long-term suction strainer performance. During some RHR and RHR service water testing, high accuracy pressure gages are installed to enhance pressure measurements. Further NRC staff review is planned to assess VY's Bulletin 95-02 responses and ECCS suction strainer performance monitoring (**IFI 95-25-03**).

3.2.4 (Open) URI 95-25-04: Augmented Off-Gas System Surveillance

Vermont Yankee identified and documented in ER 95-681 that the composition of the test gas used to calibrate the augmented off-gas (AOG) system hydrogen monitors (H_2AN-OG-2921A/B and H_2AN-OG-2922A/B) was different than that described in the TS. This discrepancy was identified during a procedural review by an I&C engineer who was investigating a report that the monitors were indicating hydrogen concentrations that differed by more than ten percent. Procedure OP 4380, "Functional Calibration of Hydrogen Detection System," prerequisite 1.a. states to use a test gas of $\geq$2% H_2 in air. TS Table 4.9.2, note 4, states that standard gas samples containing suitable concentration of hydrogen balanced nitrogen shall be used for instrument calibration.

The licensee evaluated this condition and concluded that their current calibration of the AOG hydrogen monitors was correct, however, TS Table 4.9.2 note 4 was in error and required revision to reflect the proper test gas composition. The licensee determined that the installed instrumentation required oxygen balanced nitrogen because the sensing process needs oxygen to initiate a catalytic reaction. This assessment was confirmed by the vendor of the hydrogen sensing instruments.

The inspectors confirmed that VY management ensured a timely review of this problem and directed that the resolution be completed prior to reactor startup from the automatic scram (reference Section 2.2). The Chemistry Department conducted chemical analyses and cross-checks to ascertain hydrogen concentration within the AOG system verifying that the instrumentation was properly working. The maintenance staff reviewed the preventive and corrective maintenance of the AOG system and identified no significant concerns. The inspectors verified that the hydrogen monitoring instrumentation installed to assure proper performance of the advanced offgas system required oxygen balanced nitrogen to operate.

Preliminarily, the inspectors have determined that VY has adequately resolved the problem, however, a number of weaknesses were evident. First, the Chemistry Department did not accurately interpret the hydrogen concentration within the AOG system during the initial laboratory analyses and cross-checks performed immediately after problem identification. Although subsequent evaluations were correct, the incorrect analyses demonstrated a weakness in hydrogen concentration evaluation and laboratory quality assurance methods. Second, the I&C Department did not initially fully understand the operation of the AOG hydrogen monitoring system as demonstrated by their lack of understanding of instrument operation. Third, the AOG hydrogen monitoring instrumentation TS Table 4.9.2, note 4, does not correctly reflect the test gas composition used to calibrate the instruments and appears to have been incorrect since the early 1980's. This latter problem also indicated that the biennial procedural reviews for OP 4380 were not entirely effective, in that, procedural review requirements require verification that the procedure properly implements TS requirements. Pending licensee resolution of this TS error, and further review of the implementation of biennial procedure review requirements, this item is unresolved (**URI 95-25-04**).

4.0 ENGINEERING (37551, 71707)

4.1 (Open) URI 95-25-06: Operations Impact of High Pressure Coolant Injection Design Change

On December 7, the inspector observed VY install a new type of a HPCI turbine trip pushbutton. As described in Engineering Design Change Request (EDCR) 95-408, depressing the old pushbutton caused a turbine trip and holding the button in for approximately two minutes inhibited the turbine automatic restart function. The new pushbutton maintains the push-to-trip function and includes an integral selector switch to provide a concurrent trip-and-inhibit feature. If the pushbutton collar is rotated to the trip/inhibit location, the turbine will trip (similar to depressing the button) and the inhibit signal would be locked-in, freeing the CRO from depressing the button for two minutes. Emergency Operating Procedure 3107, Appendix G, provides instructions to the CROs regarding the use of this new switch.

Prior to the conduct of the design change the inspector independently verified that the change did not result in an unreviewed safety question or change to TSs. EDCR 95-408 received the required management and PORC reviews and implementation of the EDCR met the requirements described in plant procedure AP 6004, Engineering Design Change Request. This work was pre-planned and scheduled.

The inspector observed two weaknesses associated with the implementation of the HPCI turbine trip/inhibit pushbutton selector switch design change. The first weakness was that training was not afforded to the operating staff prior to installation of the design change. Based on interviews, the on-shift CROs and operations department management did not know exactly how to operate the trip/pushbutton and incorrectly assumed that the button worked like others already installed on the control room panels. After the new pushbutton installation and inspector discussions with operations management, training was conducted. Secondly, the inspector noted that the new pushbutton position indication is not visible to the operator during operation. This poor human-system interface was similar to some refueling system controls observed previously by the NRC staff (NRC Inspection Report 93-81, Section 6.1) and reflected less than fully effective implementation of human factors guidance as described in NUREG 0700, "Guideline for Control Room Design Reviews," Section 6.0.

The operations staff was unaware of all of the consequences to the HPCI system resulting from de-energizing HPCI logic control power. In particular, when the fuses were pulled, the HPCI suction transfer logic enabled causing two motor-operated valves (HPCI-57 and 58) to open aligning HPCI pump suction to the SC. Because the CST suction valve (HPCI-17) remained in its normally open position, HPCI was also aligned to the CST. The Supervisory CRO recognized this abnormal lineup and shut HPCI-17 thus leaving HPCI suction aligned to the SC. ER 95-689 was written to evaluate and identify corrective actions for the tag-out problem. Three corrective actions were immediately identified and implemented: (1) the HPCI-17 valve was shut to prevent CST drainage into the SC; (2) the EDCR was changed to account for the system change caused by the tag-out; and, (3) department managers discussed the problem with the cognizant engineers. The inspector noted that primary containment integrity was not questioned (reference section 4.2) and no corrective actions were assigned to the Operations Department.

As described in plant procedure AP 0125, Plant Equipment Control, prior to the removal of TS equipment from service, the SS will ensure that a detailed review of the loads impacted by the de-energization of the power supply is completed. As demonstrated, this particular SS review was apparently ineffective. At the conclusion of the inspection period, VY was still evaluating the events captured in ER 95-689. NRC review of administrative controls used to ensure that: (1) modification activity will not have adverse impacts on plant operations; and (2) operational reviews, including tag-out controls, are sufficient to detect adverse system interactions when implementing design changes is unresolved pending the completion of the Vermont Yankee review **(URI 95-25-06)**.

In summary, the weaknesses described above indicated both poor engineering preparation and poor operations department staff review/verification of the system protective tag-out. Despite the normal procedure controls established to assure the safe implementation of design changes and tag-outs, the effect of the tag-out on HPCI system conditions was not fully understood by the operating and engineering staffs. This resulted in an unanticipated change in plant conditions and an unnecessary challenge for the operating crew.

4.2 (Open) URI 95-25-05): HPCI Suction Valve Logic Design Observation

The inspector performed a detailed review of the abnormal HPCI system lineup caused by the HPCI pushbutton tag-out (Section 4.1) and noted that no system damage or personnel injuries resulted. By design, the CST suction valve (HPCI-17) will start to shut when the SC suction valves start to open. This valve sequencing maintains HPCI pump suction pressure thus preventing a HPCI trip on low suction pressure. This specific sequencing contributes to reactor safety during post-accident conditions by maintaining the un-interrupted injection of high pressure cooling water. However, during the design change as discussed above, the interim piping line-up resulted in a direct water pathway between the SC and the CST vent-to-atmosphere. The only physical barriers between the SC and CST vent were one 14-inch check valve (HPCI-V-32) and the column of water existing between the HPCI pump suction and the CST. The inspector was unable to determine if this unanticipated system configuration (all three motor-operated suction isolation valves open simultaneously) potentially compromised primary containment integrity. The inspector was able to determine that the 14-inch check valve (HPCI-V-32) has not been inspected or tested in the reverse flow direction per the Inservice Testing Program.

The failure to perform inservice testing of the check valve represented another example of a recognized weakness in VY's IST Program (reference NRC Inspection Reports 95-22 and 95-23). The inspector noted that as a result of these previous NRC findings, VY is currently performing a complete IST Program review. VY management acknowledged the inspector's observations and initiated reviews to: determine whether primary containment integrity was compromised during the interim lineup; assess the CST suction transfer instructions; and determine whether the CST/SC suction transfer logic circuitry is required to meet the single failure criterion. The licensee also confirmed that the 14-inch check valve (HPCI-V-32) should have been in their IST program. The status of primary containment integrity during the interim piping lineup and the application of the single failure criteria to the SC/CST suction transfer logic circuitry is unresolved **(URI 95-25-05)**.

4.3 Loss of Stator Cooling Transient Followup

NRC Inspection Report 95-17 documented VY's initial resolution of a loss of stator cooling (LOSC) transient. The LOSC transient, as described in GE Service Information Letter (SIL) No. 581, is applicable to boiling water nuclear power plants that have high turbine bypass capability, such as VY. Assuming no operator action, this transient could result in fuel element failure. This failure could have consisted of excessive mechanical stresses within the fuel pellet and a potential for fuel clad breach. Procedure revisions were immediately implemented to resolve this problem. YNSD and GE were charged to perform a computer analysis of this transient. This period, the inspector reviewed VY's root cause evaluation, completion of long-term corrective actions, and assessed the overall handling of this industry information by the licensee.

The six member task team, chartered by VY to perform the root cause assessment and technical evaluation of the LOSC transient, was well balanced. Management oversight was provided by the Technical Services Superintendent and the task team chairperson was the Reactor and Computer Engineering Manager. Technical membership consisted of VY and YNSD engineers experienced in transient and LOCA analysis, reactor physics, and fuel performance. An operations-oriented perspective was also included in the team. Transient and fuel performance information from GE was also utilized.

The technical evaluation of the LOSC transient was comprehensive. To bound the LOSC transient, an approximate two percent margin increase to the applicable core thermal limits was imposed. This change was permanently installed into the plant process computer. No changes to TS were required. An update to the FSAR is planned. The task team appropriately reviewed and referenced VY's design bases in their safety and technical assessments. They also reviewed license commitments and regulatory requirements. Transient case studies were run at differing initial conditions to ascertain worse-case fuel performance conditions. The analytical methodologies for these case-studies were verified and validated to assure accuracy. A historical review confirmed that the plant operated within design during previous operating cycles. The inspector verified that the transient and fuel performance analyses used by VY were reviewed and approved by the NRC staff and referenced in the VY design basis.

The VY team identified the root cause as the failure to identify the LOSC transient as a limiting event during original plant licensing (circa 1971). The apparent causes involved VY's evaluation of its design basis adequacy relative to the FSAR transient analyses and YAEC's evaluation of VY's licensing basis when it was obtained from GE (circa 1980). The contributing causes were a delay in fully evaluating the LOSC transient and then a failure to recognize the need for prompt corrective actions. The inspector noted that the team identified apparent causes along with root and contributing causes. This is inconsistent with the VY Root Cause Guideline (RCG) (only apparent causes <u>or</u> root and contributing causes, not all three).

The corrective actions (CAs) were classified as Type A Commitments (the highest commitment prioritization available) and had estimated completion dates (ECDs) commensurate with the importance or significance of the particular action. However, seven of ten commitments had their ECDs extended without documented management review and five of ten were completed beyond their ECDs (even with their ECDs extended). The inspector also reviewed the completion status of ER 95-244 written for the problems associated with the main station battery (reference NRC Inspection Report 95-06) to ascertain the breadth of the above observation and noted similar commitment management problems. Of sixteen Type A commitments assigned to ER 95-244, seven were completed overdue and two were still working and overdue. Although the commitments were not rigorously administered, no safety concerns were identified.

The inspector also reviewed the CAs and found that CAs were not assigned to the root or apparent causes. The RCG indicates that a root cause should have a corrective action to fix the problem and prevent recurrence. Of the ten CAs, eight focused on the resolution of technical problems to assure safe reactor plant operations. The remaining two CAs addressed the contributing causes. Although its too early for the inspector to evaluate the effectiveness of all CAs, the CAs to resolve the technical problems appeared comprehensive and those assigned to resolve the communication problems appeared adequate. The communication CAs hinge on VY's anticipation that the engineering reorganization (see Section 5.4) will improve the four communication weaknesses identified by the team. The inspector noted that VY's documentation justifying the closure of these CAs was not included in their response to ER 95-436.

The inspector also noted that the problem statement was not clearly stated to effectively focus the team's effort and that the review of "potentially similar conditions" was not performed. VY defined the problem statement as, "More limiting [moderator temperature decrease] transient than previously identified." Although this was factual, the problem was that operating experience was not effectively evaluated by the VY organization (as the contributing causes would indicate). From this perspective, the causes correlated with the problem statement and corrective actions precluded recurrence. The identification date for the LOSC transient was when GE SIL 581 was received (April 4, 1994), not when the plant was originally licensed as the team's root cause would indicate. The team's review of potentially similar conditions focused on prior opportunities to fully evaluate LOSC-type transients.

It appeared to the inspector that the handling of this operating experience was the central problem to resolve. The inter-organizational effectiveness between VY and YAEC on this technical problem was weak, with respect to the timely resolution of this potential safety issue. This inter-organizational weakness was indicative of problems noted during past inspections in the motor operated valve (MOV) and 10 CFR 50 Appendix R programs. The VY root cause analysis appeared to have been not well focused on this central theme. Because of the CA's associated with the MOV and Appendix R problems noted above, the inter-organization weakness was being addressed by VY.

In summary, the handling and resolution of the technical problems associated with the LOSC transient were comprehensive and focused on plant safety. No safety concerns were identified by the inspector or VY. The experience and expertise of the task team members contributed to the success of their technical evaluation. However, the weaknesses identified in the root cause evaluation diminished the quality of the task team's product. In particular, the VY Root Cause Guideline was not effectively implemented for the determination of the problem statement, cause determination, and review of potentially similar conditions. In addition, the Type A commitment items for the ERs reviewed were not rigorously administered.

4.4 (Closed) URI 94-13-02: Quality Assurance of Non-nuclear Safety Components That Retain Reactor Coolant System Pressure

Unresolved item 94-13-02 involved the level of quality assurance applied to reactor coolant system (RCS) pressure boundary components that have been designated by the licensee as non-nuclear safety (NNS). The inspectors noted that quality controls as described in 10CFR50, Appendix B, Quality Assurance, were not applied to NNS components that retain RCS pressure. The particular component of concern was a pressure switch connected to the core spray system via a 1/2-inch pipe.

On September 19, 1995, VY completed their review of this concern and concluded that Appendix B quality assurance elements do not apply to components that retain RCS pressure as long as they are classified as NNS. This determination was based on VY's Safety Classification Manual (SCM) definition of NNS components and their determination that the 1/2-inch line was not part of the reactor coolant pressure boundary.

Using the NRC Standard Review Plan (NUREG-800, section 3.2.2), as a guide, the inspector reviewed VY's determination and identified no concerns with the licensee's conclusion. The VY Quality Assurance Manual (YOQAP-1A) commits to Regulatory Guide 1.26, Quality Group Classifications and Standards, and the licensee implements this NRC safety classification and quality control guidance via their SCM. The pressure switch described above and other similar components would have a level of quality assurance commensurate with their safety function and be subject to manufacturer and ANSI B31.1 standards to provide some level of assurance that NNS components meet appropriate material and design specifications.

4.5 Review of Engineering Work Tracking

The inspector conducted a review of the engineering Work Tracking System (WTS) to understand its safety function, use and content. The inspector determined that the current engineering staff WTS has been in use for approximately one year. It is a computer data-base system which receives manual input via a standard form entitled "VY Engineering & Construction Work Order". The engineering work activities entered into the system include a broad range of items (15 specified activities) from Engineering Design Change Reports, commitments, setpoint changes, and Event Reports to training courses and vacation times for individual engineers. The WTS provides individual engineers their list of work tasks to be performed with assigned priority and estimates for completion. It also provides a means by which engineering managers can track the recorded progress each engineer has made towards completion of these assigned tasks.

Based upon a sampling of individual engineer weekly WTS reports (Manhour Scheduling Reports) and discussions with responsible engineering managers, the inspector found varying degrees of use and accuracy of this system. Discussions with engineering managers identified that this observation was previously recognized by the engineering staff and was being addressed by the new engineering re-organization and management team. The WTS is currently viewed as a tool for the engineering staff and not solely depended upon for tracking such work activities as: engineering design changes, temporary and minor modifications, equivalency evaluations, commitments, and Event Reports. These activities, and others not specifically mentioned, which involve engineering resources to resolve each have a stand-alone tracking system that is monitored more closely by both the engineering and station operating staffs.

For example, the Major Projects Work List, Engineering Department Monthly Status Report, and the Weekly YNSD VY Project Report provide a summary listing of the various key engineering activities and their status with respect to established performance goals and schedule milestones (maintenance and refueling outages). These periodic summary reports highlight the significant work items in the engineering work backlog and the established priorities for their completion. Based upon a sampling review and discussion with VY managers, the inspector determined that these reports were being used by engineering and plant management to monitor, and adjust as necessary, engineering resources to meet schedular commitments and to achieve the established performance goals.

In summary, the WTS was viewed by the VY engineering staff as a management tool and not a fully matured engineering work control process, having been in use only one year. Specific types of engineering work activities have their own unique tracking system and are periodically (weekly and monthly, at a minimum) examined and reported on via summary reports to engineering and station management. The inspector found these summary reports adequate and identified no specific concerns regarding the number or types of engineering work items in backlog. VY management has adequate mechanisms currently in place to routinely monitor and assess the progress of these activities to assure timely resolution.

5.0 PLANT SUPPORT (71750, 71707)

5.1 Radiological Controls and Radiological Effluent Release Review

Inspectors routinely observed and reviewed radiological controls and practices during plant tours. The inspectors observed that posting of contaminated, high airborne radiation, radiation and high radiation areas were in accordance with administrative controls (AP-0500 series procedures) and plant instructions. High radiation doors were properly maintained and equipment and personnel were properly surveyed prior to exit from the radiation control area. Plant workers were observed to be cognizant of posting requirements and maintained good housekeeping.

The inspector reviewed VY data to assess radiological effluent releases from the main plant stack. Data reviewed included gaseous and particulate isotopic concentrations and trends as illustrated in failed fuel status reports, off-site dose calculations, and "raw" data from the main plant stack effluent charcoal and filter samples. This inspection focused on radiological data at the end of the last operating cycle (March 17, 1995) and the data and trend information from May 2, 1995, to December 15, 1995.

The inspector identified no abnormal sample or release values, or adverse trends. Trends for isotopic elements generated from reactor power operation over the operating cycle were normal. Transuranic radio-isotope daughter products from previous fuel element failures continued their downward trend. This trend included krypton, xenon, and iodine release rates. The inspector also verified that offsite dose releases at the site area boundary were within TS limits. These included iodine, tritium, and particulates, and noble gas beta and gamma. A sampling of the gaseous effluent filter analyses was examined and the inspector verified that periodic samples and analyses were conducted. Daily control room panel walkdowns and TS log reviews confirmed the operability status of the augmented offgas system and main plant stack radiation monitors. Daily the inspectors assessed the offgas rate and slope and reviewed the identified corrective maintenance list. No radiological effluent release concerns involving these systems were identified.

5.2 Security

The inspector verified that security conditions met regulatory requirements and the VY Physical Security Plan. Physical security was inspected during regular and backshift hours to verify that controls were in accordance with the security plan and approved procedures.

5.3 Fire Protection

5.3.1 Inadvertent Fire Alarm

On November 30, at approximately 9:00 a.m., the turbine truck bay fire detection system alarmed. The station fire brigade responded, accordingly. The cause of the fire detector system alarm was an open flame (propane torch) being used to install shrink wrap material on a turbine part. This truck bay maintenance evolution was planned, and the fire brigade was secured after the cause of the fire detection alarm was identified.

Inspector follow-up with the shift engineer (fire brigade leader) determined that the fire detection alarm was not anticipated. The turbine truck bay is protected from fire damage by an ultraviolet (UV) detection system (four sensors, one in each quadrant of the bay) and its associated automatic water deluge system. In preparation for the truck bay work, this system was taken to bypass because an open flame was expected to trigger the UV detectors and activate the system. However, the VY staff did not expect to receive the fire detection alarm with the system control switch in bypass.

Discussions with the control room staff identified that no specific system written guidance was available for fire protection detection or actuation circuits with respect to disabling and re-enabling these systems from service. The inspector determined that Operating Procedure (OP)-2186, "Fire Suppression Systems", provides limited fire suppression system automatic and manual actuation procedural guidance. Control room operator experience and on-the-job training currently serves to provide this type (how to bypass/abort a fire system) of plant systems knowledge. With respect to this turbine truck bay door issue, the control switch being placed in the abort/bypass position was assumed to remove both the automatic deluge and detection (alarm) function from service. As demonstrated, the alarm function was not bypassed via this control function.

Based upon the above, the control room operators initiated an ER (#95-655) to capture this event and information concerning the turbine truck bay automatic deluge system. Further review by the inspector determined that other than as-built electrical prints, none of the fire protection detection and suppression systems have written guidance to aid the operators in understanding and assuring the proper bypassing of their respective automatic detection and actuation circuits. The lack of a readily available reference material for this type of evolution was considered a procedural weakness.

5.3.2 Fire Loading Assessment

During a reactor building tour, the inspector observed workers replacing the insulation on the HPCI turbine exhaust pipe. The workers were properly following pre-planned work instructions, however, the activity resulted in a temporary accumulation of combustible materials in the immediate vicinity of the HPCI system. After discussing this observation with the control room operators, the on-shift Shift Engineer (SE) assessed this increased loading as acceptable and work continued.

The inspector noted that the HPCI system is inspected every two hours by firewatches established to compensate for licensee-identified problems with their implementation of 10CFR50, Appendix R, safe shutdown requirements. In addition, other SEs and fire protection engineers have routinely toured the area to assess fire conditions in an on-going strategy to prevent fires and enhance fire safety. Nonetheless, the inspector determined that little information exists in VY procedures as to what constitutes unacceptable transient combustible material fire loading. When the SE assessed the condition in the HPCI room, the fire loading was assessed based on experience and training. This type of subjective assessment applies to other SEs and the onsite fire protection engineers. Guidance on acceptable fire loading is not described in VY procedures or Fire Hazards Analysis. Although it would be difficult to specify explicit requirements for all conceivable combinations of fire loading throughout the plant, general guidance based on known *in-situ* combustibles and margins to fire suppression capability can be qualitatively evaluated to provide some guidance to personnel responsible for making fire safety assessments.

The Fire Protection Manager acknowledged the inspectors observations and concerns and stated that a VY internal commitment already exists to enhance the instruction and guidance provided in plant procedure AP 0042, Plant Fire Prevention and Fire Protection. The manager stated that this initiative would be expanded to include an assessment whether explicit guidance can be furnished to provide confidence that fire loading assessments are consistent and based on objective standards. The inspector had no further questions and considered the lack of explicit written guidance on specifying and assessing transient combustible material fire loading as a procedural weakness.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (71707, 40500)

6.1 (Update) VIO 94-13-01: Plant Operations Review Committee

The inspectors observed a number of PORC meetings and determined that they fulfilled TS requirements regarding the review of procedures and abnormal operating conditions. PORC meeting 95-121, focused on the immediate and long-term safety assessment of a very small pinhole leak in the service water system. The leak was of particular importance because its isolation adversely affected the operability of the fire water system. A meeting held on November 9, was a special PORC that convened to review the slow control rod scram times (reference Section 3.2.1). Although the scram times were still acceptable, the PORC reviewed the safety consequences of slow scram times and extrapolated current scram times into the future to ascertain when the margin-to-safety as defined in the TS could potentially become compromised. PORC members also discussed plans to conduct additional scram time testing, the status of replacement parts, and actions to obtain information from GE regarding potential problems with ASCO solenoid valve end-cap tolerances and the VITON diaphragm "stickiness" issue. The PORC prompted a review to ascertain whether the slowing of scram times was isolated to VY or more generic to the industry. A followup PORC on November 20 reviewed plans to conduct additional single rod scrams and questioned the adequacy of procedural controls and status of shutdown margin evaluations to support this testing.

The inspector observed the PORC's review of the proposed RHR suction strainer test, STP 95-02 (reference Section 3.2.2). During this meeting, PORC members evaluated the effect of the temporary pressure gauges on system seismic calculations, RHR pump operability with respect to suction pressures, and the actual test configuration of the RHR subsystems during the test. A discussion also focused on potential water hammer problems and system response should a loss of coolant accident and loss of offsite power occur during the special test. An appropriate safety perspective was demonstrated when a VY engineer recommended (and PORC approved) that manual operator actions should not be credited nor relied upon to take chemistry water samples from the SC during testing.

The reactive and routine PORCs observed this period appropriately focused on plant and equipment problems that had an impact on plant safety. The PORC members demonstrated a good questioning attitude during their evaluation of technical issues and provided a proper safety perspective in their decision not to rely on manual operator actions during ECCS suction strainer testing. No safety concerns or unreviewed safety questions were identified.

6.2 Review of Written Reports

The inspectors reviewed Licensee Event Reports (LERs) submitted to the NRC to verify accuracy, description of cause, and adequacy of corrective action. The inspectors considered the need for further information, possible generic implications, and whether the event warranted further onsite followup. The LERs were also reviewed with respect to the requirements of 10CFR50.73 and the guidance provided in NUREG 1022.

- LER 94-09-01, Inadvertent primary containment isolation system activation due to an unexpected transfer of the 120/240 VAC vital bus to its alternate power source during a lightning storm, dated July 20, 1995.

- LER 94-10, Non-Nuclear Safety (NNS) components acting as a primary containment boundary, dated September 9, 1994, (reference Section 4.4).

- LER 94-18 & 94-18-01, Two vital fire barriers inoperable due to degraded fire penetration seals, dated January 13, 1995 and June 7, 1995, respectively.

- LER 95-01 & 95-01-01, Failure to perform surveillances to assure primary containment integrity before releasing equipment for maintenance due to inadequate procedures, dated January 20, 1995 and June 16, 1995, respectively. The failure to perform surveillance to assure primary containment integrity were licensee identified, of minor safety significance, and corrective actions were prompt and comprehensive. This violation as described above was not cited consistent with the NRC Enforcement Policy, Section IV.

- LER 95-02 & 95-02-01, Inadequate Final Safety Analysis Report statement regarding ventilation airflow in the radwaste building during resin cask transfer, dated February 17, 1995 and July 13, 1995, respectively. The failure to perform surveillance to assure primary containment integrity were licensee identified, of minor safety significance, and corrective actions were prompt and comprehensive. This violation as described above was not cited consistent with the NRC Enforcement Policy, Section IV.

- LER 95-03, Failure to provide required emergency lighting in an area in accordance with 10CFR50 Appendix R, Section III.J, due to a failure in the management system, dated March 3, 1995.

  LER 95-03 documents the licensee's identification of inadequate emergency lighting in the intake structure for operators to locally control the service water system for alternate plant shutdown purposes. A similar event was discovered by the VY staff and reported in LER 94-11. Identification of this event was, in part, the result of corrective actions associated with LER 94-11. Additional inspection observations pertaining to emergency lighting were documented in inspection report 95-26, and are being tracked via unresolved item 94-31-02.

- LER 95-04, Incomplete repair of inoperable vital fire barrier penetration fire seal, dated April 27, 1995.

- LER 95-06, RCIC system inoperable with isolation valve in closed position due to a tripped supply breaker as a result of a low instantaneous trip setting, dated June 1, 1995.

- LER 95-14 Supplement 2, Incomplete implementation of 10CFR50 Appendix R based on identified deficiencies in the safe shutdown capability analysis, dated November 20, 1995.

Supplement 2 documents the root and contributing causes for these Appendix R deficiencies, as determined by the VY independent multi-disciplined team. A detailed NRC staff review of the identified deficiencies was documented in NRC Inspection Report 95-26. Based upon this review, additional inspection followup of the VY root cause evaluation and corrective action was anticipated and will be tracked independent of LER 95-14 and its two supplements.

- LER 95-16, Stack particular filter used in composite sample to detect alpha and strontium 89 and 90 was misplaced due to inadequate tracking methods, dated August 28, 1995.

- LER 95-17 and Supplement 1, Technical Specification 4.6.E not met due to components not included in the Inservice Test Program, dated October 27, 1995 and November 30, 1995, respectively.

  The subject of this LER was identified by NRC inspectors, as documented in NRC Inspection Report 95-22. Enforcement action was taken and issued by letter dated October 20, 1995. Inspector followup and review of licensee corrective actions will be tracked via violations 95-22-01, 02, and 03. This LER is closed.

- LER 95-18 and Supplement 1, Inadequate IST surveillance and Regulatory Guide 1.97 submittal information on the recirculation loop sample line isolation valves due to misinterpretation of the existing design configuration during program development, dated October 26, 1995 and November 30, 1995, respectively.

  Based upon an inquiry by another nuclear facility, the VY staff identified that control power and indication circuit for valves FCV 2-39 and FCV 2-40 (inside and outside containment recirculation loop sample isolation valves) did not satisfy Reg Guide 1.97 non-redundant power source requirements, did not provide direct valve position indication, and as a result, neither valve had been appropriately tested per the Inservice Testing Program. The subject valves are air-operated, 3/4-inch globe valves which: are normally closed; receive a close signal from the primary containment isolation system Group 1 logic; and fail closed on a loss of air or control power. These valves provide an alternate means of obtaining a reactor coolant chemistry sample in the event the normal sample path, via the reactor water cleanup system, is unavailable.

  Upon identification of these deficiencies, the VY staff initiated prompt action to remove electrical power and protective tag the valve control switches on the control room panel per TS 3.7.D.2. The FCV 2-40 valve has subsequently been verified closed daily per TS 4.7.D.2. Inspector review of the short and long term corrective actions for this licensee identified problem determined that the VY staff has developed a comprehensive plan which includes: the review of the adequacy of earlier Reg Guide 1.97 commitments and submittals; a review of all power operated valve position indicator circuits for similar design deficiencies; and a commitment to implement a design change to facilitate proper inservice testing of FCV 2-39 and 40 prior to startup from the 1998 Refueling Outage. VY determined the root cause to be a misinterpretation of the existing design configuration, in that, it was not recognized that FCV-2-39/40 should have met Reg Guide 1.97 power source requirements.

These sample valve design and resultant testing deficiencies were licensee identified, of minor safety consequence, and corrective actions were prompt and comprehensive. This violation as described above was not cited, consistent with Section IV of the NRC's Enforcement Policy.

- LER 95-19, Vital fire door declared inoperable due to inability to satisfy surveillance acceptance criteria, dated November 6, 1995.

  The reactor building (North) secondary containment airlock entrance outer door was identified not to have an approved latch mechanism installed. The VY staff identified this discrepancy as part of the plant-wide baseline fire door inspection and evaluation. The inspector verified appropriate compensatory measures were initiated until an approved latch mechanism was procured and installed. VY plans to submit a supplement to the LER to document the detailed root cause analysis results for this event.

Periodic and Special Reports

Vermont Yankee submitted the following periodic and special reports which were reviewed for accuracy and found to be acceptable:

- Monthly Statistical Report for October and November, 1995

7.0 MANAGEMENT MEETINGS

Meetings were held periodically with VY management during this inspection to discuss inspection findings. A summary of preliminary findings was also discussed at the conclusion of the inspection and prior to report issuance. No proprietary information was identified as being included in this report.