May 1, 2007

Mr. Theodore A. Sullivan
Site Vice President
Entergy Nuclear Operations, Inc.
Vermont Yankee Nuclear Power Station
320 Governor Hunt Road
Vernon, VT 05354

SUBJECT: VERMONT YANKEE NUCLEAR POWER STATION - NRC INTEGRATED INSPECTION REPORT 05000271/2007002

Dear Mr. Sullivan:

On March 31, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Vermont Yankee Nuclear Power Station. The enclosed report documents the inspection findings which were discussed on April 10 and April 23, 2007, with you and members of your staff.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one NRC-identified finding and three self-revealing findings of very low safety significance (Green). Two of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Manual. If you contest any NCV in this report, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the United States Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at Vermont Yankee Nuclear Power Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the

NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Raymond J. Powell, Chief
Projects Branch 5
Division of Reactor Projects

Docket No.: 50-271
License No.: DPR-28

Enclosure: Inspection Report 05000271/2007002
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.:	50-271
Licensee No.:	DPR-28
Report No.:	05000271/2007002
Licensee:	Entergy Nuclear Operations, Inc.
Facility:	Vermont Yankee Nuclear Power Station
Location:	320 Governor Hunt Road Vernon, Vermont 05354-9766
Dates:	January 1, 2007 through March 31, 2007
Inspectors:	David L. Pelton, Senior Resident Inspector Beth E. Sienel, Resident Inspector James D. Noggle, Senior Health Physicist
Approved by:	Raymond J. Powell, Chief Projects Branch 5 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000271/2007002; 01/01/07 - 03/31/07; Vermont Yankee Nuclear Power Station; Maintenance Effectiveness, Operability Evaluations, Surveillance Testing, and Event Follow-Up.

This report covered a 13-week period of inspection by resident inspectors and an announced inspection by a regional senior health physics inspector. Four green findings, two of which were also non-cited violations (NCVs), were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using the Inspection manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level afer NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

Green. A self-revealing finding was identified because Entergy mechanics did not meet station expectations for establishing minimum thread engagement when installing packing gland studs into the “A” service water pump stuffing box during the replacement of pump packing. The lack of adequate stud engagement ultimately resulted in the gland studs backing out of the stuffing box and the extrusion of packing from the “A” service water pump. Entergy personnel took immediate actions to re-install the gland studs, replace the extruded packing, and return the “A” service water pump to available status approximately 10 hours later.

The finding is more than minor because it is associated with the Equipment Performance attributes of both the Initiating Events and Mitigating Systems Cornerstones and because it affects the associated Cornerstone objectives of limiting the likelihood of those events that upset plant stability and ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors conducted a Phase 2 analysis and determined that the finding was of very low safety significance. (Section 1R12)

Green. A self-revealing finding was identified due to a procedure performance error made by Electrical Maintenance Department technicians while performing switchyard testing. As a result, one of three 345 kilovolt offsite power lines and one of two 115 kilovolt power supplies to the startup transformers were inadvertently isolated requiring control room operators to reduce reactor power to approximately 65 percent to meet grid stability limits. This procedure performance error was entered into Entergy’s corrective action program for resolution.

The finding is more than minor because it is associated with the Equipment Performance-Maintenance attribute of the Initiating Events Cornerstone and affected the associated cornerstone objective of limiting the likelihood of those events that upset plant stability (i.e., performance of a power reduction). The finding is of very low safety significance because performing the power reduction did not contribute to the likelihood of both a reactor trip and the unavailability of mitigating equipment. The cause of this finding is related to the cross-cutting area of Human Performance, in that, technicians failed to follow procedures. (Section 4OA3.3)

Cornerstone: Mitigating Systems

Green. The inspectors identified an NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control." Specifically, Entergy did not use an appropriate method for calculating the effects of vortexing within the condensate storage tank which could have impacted high pressure coolant injection system and reactor core isolation cooling system performance under certain accident conditions. This design control issue was entered into Entergy's corrective action program for resolution. Immediate corrective actions taken by Entergy included maximizing the available volume of water in the condensate storage tank and requiring control room operators to manually realign the suction of the high pressure coolant injection and reactor core isolation cooling systems from the condensate storage tank to the torus if level decreased below 17.5 percent.

The finding is more than minor because it is associated with the Design Control attribute of the Mitigating Systems Cornerstone and because it affects the associated Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesired consequences. The finding is of very low safety significance because it did not result in a loss of operability of either the high pressure coolant injection system or the reactor core isolation cooling system. The cause of this finding is related to the cross-cutting area of Problem Identification and Resolution, in that, Entergy did not effectively evaluate relevant internal and external operating experience related to non-conservative condensate storage tank vortexing analyses. (Section 1R15)

Green. A self-revealing NCV of Vermont Yankee Technical Specification 6.4, "Procedures," was identified when operators failed to follow a surveillance procedure for the emergency diesel generator fuel oil transfer system. As a result, the "A" diesel automatically shut down and was declared unavailable when its fuel oil supply was isolated. Entergy restored the system to a standby alignment and entered this issue into their corrective action program.

The finding is more than minor because it is associated with the Equipment Performance attribute of the Mitigating Systems Cornerstone and because it affects the associated Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding is of very low safety significance because it did not result in a loss of system safety function; did not represent actual loss of safety function of a single train for greater than its Technical Specification allowed outage time; and was not risk significant due to seismic, flooding, or severe weather initiating events. The cause of this finding has a cross-cutting aspect in the area of Human Performance, in that, personnel failed to follow the established procedure. (Section 1R22)

B. Licensee-Identified Findings

None.

REPORT DETAILS

Summary of Plant Status

Vermont Yankee (VY) Nuclear Power Station began the inspection period operating at full power. A planned reactor power reduction to approximately 58 percent was performed on February 13, 2007, to support a control rod pattern adjustment and main steam system valve testing. The plant was returned to full power the following day. A planned reactor power reduction to approximately 70 percent was performed on March 18, 2007, to support maintenance on switchyard electrical breaker 379. The plant was returned to full power the following day. An unplanned power reduction to 65 percent was performed on March 24, 2007, as a result of procedural errors made during switchyard breaker testing (Section 4OA3.3). The plant was returned to full power later that same day. A planned reactor power reduction to approximately 70 percent was performed on March 25, 2007, to support the return to service of switchyard electrical breaker 379. The plant was returned to full power the following day. With the exception of additional minor power reductions to support rod pattern adjustments, VY remained at full power throughout the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Seasonal Susceptibilities

a. Inspection Scope (one sample)

The inspectors reviewed measures established by Entergy for coping with cold weather effects on the alternate cooling system (ACS), high pressure coolant injection (HPCI) system and the reactor core isolation cooling (RCIC) system. The inspectors reviewed the system design basis documentation and performed a partial walkdown of accessible portions of the various freeze protection measures provided for these systems (e.g., temporary room heating, electrical heat tracing, etc.). The inspectors evaluated the adequacy of these cold weather coping strategies against the requirements of Vermont Yankee Operating Procedure (OP) 2196, “Preparations for Cold Weather Operations,” and the subfreezing operation of cooling towers section of OP 2180, “Circulating Water/Cooling Tower Operation.” Additionally, the inspectors reviewed condition reports (CRs) related to cold weather protection provided for the HPCI, RCIC, and ACS systems to ensure problems were properly addressed for resolution.

b. Findings

No findings of significance were identified.

.2 Readiness for Impending Adverse Weather Conditions

a. Inspection Scope (one sample)

On March 8,2007, the inspectors reviewed actions taken by Entergy due to severe cold weather in the vicinity of the plant. The inspectors reviewed procedure OP 3127, Appendix D, "Extreme Low Temperature Walkdown Check Sheet," and performed independent walkdowns of systems listed in Appendix D, including the HPCI, RCIC, and the emergency diesel generator (EDG) systems, to determine the impact of severe cold weather on these systems. The inspectors also performed a walkdown of the condensate storage tank (CST) enclosure to verify the temperature in the vicinity of the CST level instrumentation and associated HPCI and RCIC suction automatic transfer instrumentation remained above the temperature required by the environmental qualification program.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial Equipment Alignment (71111.04)

a. Inspection Scope (six samples)

The inspectors performed six partial system walkdowns of risk-significant systems to verify system alignment and to identify any discrepancies that could impact system operability. Observed plant conditions were compared to the applicable standby alignment of equipment specified in OP 2121, "Reactor Core Isolation Cooling System;" OP 2124, "Residual Heat Removal System;" OP 2123, "Core Spray System;" OP 2181, "Service Water/Alternate Cooling Operation Procedure;" and OP 2126, "Diesel Generators." The inspectors observed valve positions, the availability of power supplies, and the general condition of selected components to verify there were no obvious deficiencies. The inspectors verified the alignment of the following systems:

- The RCIC system while the HPCI system was out of service for planned maintenance;
- The residual heat removal (RHR) system and the core spray (CS) system during the repair of "B" RHR pump discharge check valve V10-48B;
- The service water (SW) system while the "A" SW pump was out of service for planned maintenance;
- The "A" EDG while the "B" EDG out of service for planned maintenance;
- The RHR system while the "D" RHR pump was out of service for planned maintenance; and
- The SW system following the failure of the packing in the "A" SW pump.

b. Findings

No findings of significance were identified.

.2 Complete Equipment Alignment (71111.04S)

a. Inspection Scope (one sample)

The inspectors performed a complete equipment alignment walkdown of the primary containment pressure suppression vacuum breakers. This inspection included both the torus-to-reactor building vacuum breakers and the torus-to-drywell vacuum breakers. The walkdown was performed by comparing actual valve alignments to approved piping and instrumentation diagrams and to system lineups contained in OP 2115, "Primary Containment." The inspectors also considered vacuum breaker alignment and system descriptions contained in the updated final safety analysis report (UFSAR), technical specification (TS), and applicable design basis documents. The inspectors ensured required position indication systems were functional, supports and hangers were correctly installed, ancillary equipment did not interfere with the operation of these valves, and that there were no unidentified deficiencies. Additionally, the inspectors reviewed open maintenance work requests and CRs related to the vacuum breakers to confirm that open items did not impact system operability.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Quarterly Inspection (71111.05Q)

a. Inspection Scope (nine samples)

The inspectors identified fire areas important to plant risk based on a review of Entergy's Vermont Yankee Safe Shutdown Capability Analysis, the Fire Hazards Analysis, and the Individual Plant Examination External Events (IPEEE). The inspectors toured plant areas important to safety in order to verify the suitability of Entergy's control of transient combustibles and ignition sources, and the material condition and operational status of fire protection systems, equipment, and barriers. The following fire areas (FAs) and fire zones (FZs) were inspected:

- Reactor building, 303 foot elevation (FZ RB7);
- Reactor building, 280 foot elevation, recirculation system motor generator area (FZ RBMG);
- Reactor building, 252 foot elevation, S1 cable trays (FZ 3/4);
- Reactor building, 252 foot elevation, S2 cable trays (FZ 3/4);
- Reactor building, 252 foot elevation, North (FZ RB3);
- Reactor building, 252 foot elevation, South (FZ RB4);

- Torus room, 213 foot elevation, North (FZ RB1);
- Torus room, 213 foot elevation, South (FZ RB2); and
- Turbine building, all areas (FA TB).

b. Findings

No findings of significance were identified.

.2 Annual Inspection (71111.05A)

a. Inspection Scope (one sample)

On January 26, 2007, the inspectors observed the performance of an announced fire drill involving a simulated fire in the radiologically controlled area chemistry laboratory. The inspectors evaluated the readiness of the fire brigade against the drill objectives and acceptance criteria established within the drill scenario including:

- Leadership ability of the brigade leader;
- Donning of protective clothing;
- Use of self-contained breathing apparatus equipment;
- Fire brigade control of the affected area;
- Use and availability of fire fighting equipment; and
- Communications between the fire brigade, the main control room, and security personnel.

The inspectors observed debriefing activities between the drill evaluators and the fire brigade to ensure lessons learned were communicated to fire brigade members. The inspectors also reviewed CRs related to fire brigade readiness to verify that Entergy identified issues at an appropriate threshold and entered them into the corrective action program.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (one sample)

The inspectors reviewed Entergy's established flood protection barriers and procedures for coping with external flooding events. The inspectors reviewed external flooding information contained in Entergy's External Events Design Basis Document and compared it to required flooding actions delineated in OP 3127, "Natural Phenomena." The inspectors performed walkdowns of flood-vulnerable areas and ensured equipment needed to mitigate an external flooding event (e.g., sump pumps, floor drain plugs, etc.) was available and in working order. The inspectors also reviewed a sample of problems identified in Entergy's corrective action program to verify that Entergy identified and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11Q)

a. Inspection Scope (one sample)

The inspectors observed simulator-based licensed operator requalification training provided to operators. The inspectors evaluated crew performance in the areas of clarity and formality of communications; ability to take timely actions; prioritization, interpretation, and verification of alarms; procedure use; control board manipulations; oversight and direction from supervisors; and command and control. Crew performance in these areas was compared to Entergy management expectations and guidelines as presented in Vermont Yankee Administrative Procedure (AP) 0151, "Responsibilities and Authorities of Operations Department Personnel;" AP 0153, "Operations Department Communication and Log Maintenance;" and Vermont Yankee Department Procedure (DP) 0166, "Operations Department Standards." The inspectors also compared simulator configurations with actual control board configurations. The inspectors also observed Entergy evaluators discuss identified weaknesses with the crew and/or individual crew members, as appropriate.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q)

a. Inspection Scope (three samples)

The inspectors performed two issue/problem-oriented inspections of actions taken by Entergy in response to a trip of the "B" EDG due to the inadvertent isolation of fuel during fuel oil transfer system testing and the failure of the "A" SW system pump packing. The inspectors also performed one system/function performance history-oriented inspection of the John Deere diesel generator, a system recently designated as (a)(1). The inspectors reviewed work practices that may have contributed to degraded system performance, Entergy's ability to identify and address common cause failures, the applicable maintenance rule scoping document for each system, the current classification of these systems in accordance with 10 CFR 50.65 (a)(1) or (a)(2), the applicable system (a)(1) performance evaluation, and the adequacy of the performance criteria and goals established for each system. The inspectors also reviewed recent system health reports and/or discussed system performance with the responsible system engineer.

b. Findings

Introduction: A self-revealing finding was identified because Entergy mechanics did not meet station expectations for establishing minimum thread engagement when installing packing gland studs into the “A” SW pump stuffing box during the replacement of pump packing. The lack of adequate stud engagement ultimately resulted in the gland studs backing out of the stuffing box and the extrusion of packing from the “A” SW pump.

Description: On March 2, 2007, Entergy personnel identified water spraying from the “A” SW pump stuffing box. This pump is located in the plant’s intake structure. Further inspection revealed that the gland studs had completely backed out and were lying on the intake structure floor and the packing had been extruded from the stuffing box. Water spraying from the pump stuffing box was impinging on the pump motor and had washed grease out of the motor lower bearing guide. Operators manually secured the “A” SW pump, declared the pump inoperable, and entered the associated TS limiting condition for operation. The inspectors performed a walkdown in the vicinity of the “A” SW pump immediately following the identification of excessive leakage and reviewed actions taken by control room operators to address the pump’s continued operability and availability. Entergy personnel took immediate actions to re-install the gland studs, replace the extruded packing, and return the “A” SW pump to available status approximately 10 hours later.

Entergy entered this issue into their corrective action program (CR 2007-0652) and performed an apparent cause evaluation (ACE). In the ACE, Entergy identified four issues that contributed to the extrusion of the “A” SW pump packing:

- On February 6, 2007, mechanics replaced the “A” SW pump packing; however, mechanics did not fully engage the gland studs into the stuffing box. The gland studs, gland nuts, and gland follower maintain the integrity of the motor-end of the packing arrangement;
- The pump throttle bushing was discovered to be worn resulting in the clearance between the bushing and the pump shaft exceeding the pump manufacturer’s specification. The throttle bushing (essentially a brass washer) is mounted on the pump shaft between the pump housing and the stuffing box. The bushing reduces the amount of pump discharge pressure exerted on the pump-end of the packing arrangement. The worn bushing caused greater than normal pressure to be exerted on the packing arrangement;
- During the packing replacement, mechanics did not follow the work order (WO) requirements for the use of spacers in the packing arrangement; and
- The WO for the packing replacement was inconsistent with the packing manufacturer’s instructions in regards to the use of spacers in the packing arrangement.

The inspectors reviewed Entergy’s ACE; reviewed WO 00102744-01, “Replace Tom-Pac Packing,” which contained the instructions used by the mechanics during the February pump packing replacement; and reviewed the station expectations and training provided to mechanics regarding fastener (e.g., bolts, studs, screws, etc.) installation and removal. Finally, the inspectors interviewed mechanics, engineers, and work planners involved with the "A" SW pump packing replacement.

In order to replace the pump packing, mechanics first removed the gland studs and gland follower to gain access to the stuffing box and packing. WO 00102744-01 did not include instructions for the removal and reinstallation of these components. These components were removed and reinstalled using "skill of the craft." As defined in Entergy Nuclear Management Manual EN-WM-105, "Planning," the term "skill of the craft" refers to standard industry work skills that are common knowledge to individuals performing work and include skills taught by a formal training program. Entergy's formal training program provided for mechanics includes lesson plan MMC-03-002, "Fasteners and Torque Requirements." Included in this lesson plan are general bolting guidelines which include expectations for minimum thread engagement needed for studs installed in a blind hole (one stud diameter engagement is required) and a general expectation that mechanics verify proper thread engagement on stud-nut fasteners.

Based on the above, the inspectors concluded that the extrusion of packing from the "A" SW pump was due to the failure of the mechanics to meet station expectations for establishing minimum thread engagement when installing the packing gland studs into the "A" SW pump. Contributing to the packing extrusion was the increased pressure exerted on the packing arrangement due to the worn throttle bushing. The inspectors reviewed available operating experience (OE) regarding worn throttle bushings and their impact on pump packing and seal performance. While worn throttle bushings have been know to contribute to pump seal and packing leakage, the OE information did not indicate that worn bushings lead to pump packing failures. Finally, the inspectors concluded that errors made with the use of spacers in the packing arrangement, while not consistent with the WO or with the packing manufacturer's instructions, did not contribute to the packing extrusion.

Analysis: The performance deficiency associated with this finding is Entergy mechanics did not meet station expectations for installing packing gland studs in the "A" SW pump stuffing box during the replacement of pump packing. The lack of adequate stud engagement ultimately resulted in the gland studs backing out of the stuffing box and the extrusion of packing from the "A" SW pump. The finding is greater than minor since it is associated with the Equipment Performance attributes of both the Initiating Events and Mitigating Systems Cornerstones and because it affects the associated Cornerstone objectives of limiting the likelihood of those events that upset plant stability and ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The finding was determined to be of very low safety significance (Green) in accordance with Inspection IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," using the Phase 1, Phase 2 and Phase 3 of the SDP. The inspectors performed a Phase 1 screening and determined that a Phase 2 analysis was required since the finding affected two or more cornerstones. A Senior Reactor Analyst (SRA) performed a Phase 2 analysis using the site specific risk-informed inspection notebook. The SRA used the following assumptions during the performance of the Phase 2: the SW system at VY is considered to be a normally cross-tied support system and therefore the likelihood of a loss of service water initiating event was increased by one order of magnitude; the length of time the “A” SW pump was unavailable due to the packing extrusion was less than three days; and the SW system function was maintained as a result of the continued operability of the remaining three SW pumps. After evaluating all the SDP notebook worksheets and applying the counting rule, the SRA determined the increase in core damage frequency was in the range (low E-7) where a Phase 3 analysis was appropriate to determine if the increase in large early release frequency and external initiating events needed to be evaluated.

The SRA performed a Phase 3 analysis using the VY Standardized Plant Analysis Risk (SPAR) model. The SRA determined that the increase in core damage frequency was in the range of 1 in 14,000,000 years of operation (high E-8 range), assuming that the “A” SW pump was inoperable and that the loss of service water initiating event frequency increased for the 10 hour exposure time. This result indicated that further analysis of the increase in large early release frequency and external initiating events was not needed. The SPAR model dominate core damage sequence, given the assumed conditions, was a loss of electrical Bus 3 initiating event with the failure or the inability of operators to vent containment. The SRA noted that given this initiating event and the assumed conditions, only one SW pump would remain functional, which would be insufficient to proved adequate cooling to ensure removal of decay heat from the primary containment.

Because this finding does not involve a violation of regulatory requirements and has very low safety significance, it is identified as FIN 05000271/2007002-01, Failure to Establish Minimum Thread Engagement for the “A” SW Pump Packing Gland Studs Results in Unplanned unavailability.

Enforcement: No violation of NRC regulatory requirements was identified. Although mechanics did not meet station expectations for establishing minimum thread engagement when installing packing gland studs into the “A” SW pump, the performance of maintenance activities using “skill of the craft” does not fall under NRC regulatory requirements.

1R13 Maintenance Risk Assessment and Emergent Work Evaluation (71111.13)

a. Inspection Scope (six samples)

The inspectors evaluated online risk management for four planned maintenance activities and two emergent/unplanned repair activities. The inspectors reviewed maintenance risk evaluations, work schedules, recent corrective actions, and control room logs to verify that other concurrent or emergent maintenance activities did not significantly increase plant risk. The inspectors compared reviewed items and activities to requirements listed in AP 0125, "Plant Equipment" and AP 0172, "Work Schedule Risk Management - Online." The inspectors also walked down areas of the plant containing equipment that was determined to have higher risk significance during the following work activities:

- Planned maintenance on the HPCI system;
- Planned maintenance on the “B” RHR system pump discharge valve V10-48B;
- Planned maintenance on the “A” SW system pump;
- Planned maintenance on the “B” EDG;
- Emergent repair of the “A” SW pump packing; and
- Unplanned downpower due to errors made during switchyard testing.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (four samples)

The inspectors reviewed four operability determinations prepared by Entergy. The inspectors evaluated the operability determinations against the guidance contained in NRC Inspection Manual Part 9900, Technical Guidance, “Operability Determinations and Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety,” as well as Entergy procedure ENN-OP-104, “Operability Determinations.” The inspectors verified the adequacy of the following evaluations of degraded or non-conforming conditions:

- Main steam isolation valve 86D did not meet closure time testing requirements;
- The “B” RHR service water pump failed to meet in-service testing requirements;
- Inadequate design control associated with the CST vortexing analysis; and
- SW system pump motor air cooling flow found to be below values described in station drawings.

b. Findings

Introduction: The inspectors identified an NCV of very low safety significance (Green) of 10 CFR 50, Appendix B, Criterion III, “Design Control.” Specifically, Entergy did not use an appropriate method for calculating the effects of vortexing within the CST which could have impacted HPCI system and RCIC system performance under certain accident conditions.

Description: During a small or intermediate break loss of coolant accident (LOCA), the HPCI and RCIC systems may start automatically and inject water from the CST to the reactor vessel. As CST level decreases, the suction paths for the HPCI and RCIC systems will automatically realign from the CST to the suppression pool (torus) to protect these systems from the effects of vortex formation within the CST. The effects of vortexing can include air entrainment, pump damage, and the potential for insufficient post-accident reactor vessel injection flow.

Through discussions with NRC staff and review of available OE information (e.g., NRC inspection findings, NUREGs, etc.), the inspectors identified that the methodology employed by Entergy to evaluate the effects of CST vortexing may not be appropriately conservative. As a result, the setpoint selected for the HPCI and RCIC system suction automatic realignment may not protect these systems from the effects of vortexing.

The inspectors discussed this issue with Entergy design engineering personnel who performed a review of Vermont Yankee Calculation (VYC) 1844, "HPCI and RCIC Vortex Height," Revision 1. This calculation provides the design basis for the minimum level of water needed in the CST to avoid vortex formation under accident conditions. The original method used in VYC 1844 was similar to the Harleman method cited in various OE documents as a potentially non-conservative methodology due to assumptions made regarding fluid density and viscosity. VYC 1844 indicated that the minimum CST water level needed to avoid vortex formation was approximately 28 inches. When Entergy engineers applied alternative analytical methods discussed in OE documents including the Alden Laboratory and Reddy-Pickford methods, they determined that the minimum CST level needed to avoid vortex formation was approximately 67 inches. Based on this, Entergy agreed that the analytical method originally used to determine the effects of vortexing within the CST was not appropriately conservative.

Entergy personnel initiated CR 2007-0132 and completed an operability evaluation to fully evaluate the CST vortexing concern. Immediate corrective actions taken as a result of this evaluation included maximizing the available volume of water in the CST and requiring control room operators to manually realign the suction of the HPCI and RCIC systems from the CST to the torus if level decreased below 17.5 percent or approximately 70 inches. The inspectors verified that these actions were included in control room standing orders pending incorporation into appropriate station procedures.

Despite this design control deficiency, the inspectors concluded that the HPCI and RCIC systems remained operable based on the following:

- Actual CST water level is, and has been, administratively controlled above the minimum needed to avoid vortex formation during a small or intermediate break LOCA. Therefore, the HPCI and RCIC systems will have injected the required volume of water into the reactor vessel before vortexing would occur in the CST; and

- During non-LOCA events, operators take manual control of the HPCI and/or RCIC systems and reduce system flowrate to maintain reactor vessel level within the range specified in the emergency operating procedures. Reducing system flowrate reduces the magnitude of vortex formation such that there would be no significant effect on HPCI or RCIC system performance.

Analysis: The performance deficiency associated with this finding was that Entergy did not use an appropriate method for calculating the effects of vortexing within the CST or its impact on the HPCI and RCIC systems. The inspectors determined that this design control deficiency was within Entergy's ability to identify and correct prior to January 2007 based on available industry OE information. The finding is more than minor because it is associated with the Design Control attribute of the Mitigating Systems Cornerstone and because it affects the associated Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesired consequences. The inspectors conducted a Phase 1 screening of the finding in accordance with IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The finding was determined to be of very low safety significance (Green) because the design control deficiency did not result in a loss of operability of either the HPCI or RCIC systems.

The inspectors determined that the cause of this finding was related to the cross-cutting area of Problem Identification and Resolution. Entergy did not effectively evaluate relevant internal and external OE related to non-conservative CST vortexing analyses.

Enforcement: 10 CFR 50, Appendix B, Criterion III, "Design Control," states, in part, that measures shall be established for the selection and review for suitability of application of processes that are essential to the safety-related functions of the structures, systems and components. Contrary to the above, as of January 15, 2007, Entergy had not selected or reviewed for suitability an adequately conservative method for calculating the effects of CST vortexing on the HPCI and RCIC systems. Specifically, VYC 1844, "HPCI and RCIC Vortex Height," Revision 1, completed on February 24, 1999 used a method to calculate the minimum CST water level needed to avoid vortexing which yielded a non-conservative result when compared to the results of more recent and more appropriate methodologies. Because this design control deficiency is of very low safety significance and has been entered into Entergy's corrective action program (CR 2007-0132), this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000271/2007002-02, Inadequate Design Control Associated with CST Vortexing Analysis.

1R17 Permanent Plant Modifications (71111.17A)

a. Inspection Scope (one sample)

The inspectors reviewed design change documentation associated with the permanent installation of calibration test equipment in and around primary instrumentation racks. This test equipment included test tanks, tubing, and isolation valves used to support the calibration of various safety-related instrumentation (e.g., reactor vessel level, reactor pressure, etc.). The inspectors reviewed these design changes to verify that the design bases, licensing bases, and performance capability of affected instrumentation had not been degraded. The inspectors also focused on the impact the permanent plant change had on operator actions and changes to key safety functions. The selection of permanent plant changes for review was based on a review of risk insights and on a review of available OE information. The inspectors walked down associated instrument racks; interviewed plant staff; and reviewed applicable procedures, calculations, modification packages, engineering evaluations, drawings, engineering requests, the UFSAR and TS.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope (eight samples)

The inspectors reviewed eight post-maintenance testing (PMT) activities on risk-significant systems. The inspectors either directly observed the testing or reviewed completed PMT documentation to verify that the test data met the required acceptance criteria contained in the applicable WO, TS, UFSAR, and/or inservice testing program. Where testing was directly observed, the inspectors verified that installed test equipment was appropriate and controlled and the test was performed in accordance with applicable station procedures. The inspectors also verified that the test activities were adequate to ensure system operability and functional capability following maintenance, systems were properly restored following testing, and any discrepancies were appropriately documented in the corrective action program. The inspectors reviewed the following PMT activities:

- Testing of the HPCI system following planned maintenance, in accordance with OP 5220, “Limitorque Operator PM,” and OP 4120, “High Pressure Coolant Injection System Surveillance;”
- Testing of the “B” RHR pump following planned maintenance on pump discharge valve V10-48B, in accordance with OP 4124, “Residual Heat Removal and RHR Service Water System Surveillance;”
- Testing of the SW system following “A” SW pump motor replacement, in accordance with OP 4181, “Service Water/Alternate Cooling System Surveillance;”
- Testing of the “B” EDG following planned maintenance, in accordance with OP 4126, “Diesel Generator Surveillance;”
- Testing of the “B” control rod drive pump following pump motor replacement, in accordance with WO 51057268;
- Testing of the “B” RHR pump circuit breaker following position indication repair, in accordance with OP 2124, “Torus Cooling;”
- Testing of the “A” SW pump following emergent replacement of pump packing, in accordance with OP 4181; and
- Testing of the diesel driven fire pump following start solenoid replacement, in accordance with OP 4105, “Fire Protection Systems Surveillance.”

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (six samples)

The inspectors observed surveillance testing to verify that the test acceptance criteria specified for each test was consistent with TS and UFSAR requirements, the test was performed in accordance with the written procedure, the test data was complete and met procedural requirements, and the system was properly returned to service following testing. The inspectors observed selected pre-job briefs for the test activities. The inspectors also verified that discrepancies were appropriately documented in the corrective action program. The inspectors verified that the following surveillance testing activities met the above requirements:

- Diesel and electric fire pump monthly testing (routine test), in accordance with OP 4105;
- "B" CS system quarterly testing (in-service test), in accordance with OP 4123, "Core Spray System Surveillance;"
- Diesel fuel oil transfer pump comprehensive test and discharge valve operability test (in-service test), in accordance with OP 4195, "Fuel Oil Transfer System Surveillance;"
- HPCI system logic testing (routine test), in accordance with OP 4360; "HPCI System Actuation Logic Functional/Calibration Test;"
- Drywell leakage calculation (RCS leak detection), in accordance with OP 4152, "Equipment and Floor Drain Sump and Totalizer Surveillance; and
- Review American Society of Mechanical Engineers (ASME) buried component testing requirements for applicability to Entergy's in-service testing program for the SW system.

b. Findings

Introduction: A self-revealing NCV of TS 6.4, "Procedures," was identified when operators failed to follow a surveillance procedure for the EDG fuel oil transfer system. As a result, the "A" EDG automatically shut down and was declared unavailable when its fuel oil supply was isolated.

Description: On February 12, 2007, with the reactor operating at 100 percent power, operators performed the "A" EDG slow start operability test in accordance with OP 4126, "Diesel Generators Surveillance." Concurrent with this test, operators commenced a planned diesel fuel oil transfer pump comprehensive test and discharge valve operability test in accordance with OP 4195, "Fuel Oil Transfer System Surveillance." In order to establish test conditions, an EDG must be run to allow the level in the EDG fuel oil day tank to decrease to less than or equal to 30 inches. Once this condition is established, OP 4195 then directs the operators to secure the EDG and throttle the fuel oil day tank inlet isolation valve, FO-14A for the "A" EDG, to obtain a specified transfer pump discharge pressure. In this case, operators failed to secure the "A" EDG. Additionally, at the step where FO-14A was to be throttled, the operator incorrectly throttled the day tank outlet valve to the "A" EDG, FO-40A. Because the operator did not see the expected response in the transfer pump discharge pressure when the valve was throttled in the closed direction, the valve was eventually throttled to the fully closed position. At this point, the fuel oil supply was isolated to the operating diesel and it automatically tripped, as expected, on a reverse power lock-out. As a result, the "A" EDG was considered unavailable for approximately 6.5 hours while the event was investigated and the EDG was returned to a standby alignment.

Entergy entered this event into their corrective action program as CR 2007-0483. In the associated root cause analysis, Entergy determined the root causes of the event to be 1) operators failed to follow the EDG and fuel oil transfer system surveillance procedures and allowed the "A" EDG to remain running during the transfer system surveillance, and 2) the operator failed to effectively self-check to ensure the correct valve was operated which caused the fuel oil supply to the operating EDG to be isolated.

Analysis: The performance deficiency associated with this finding is that operators failed to follow the EDG fuel oil system surveillance procedure. As a result, the "A" EDG automatically shut down and was declared unavailable for 6.5 hours. The finding is more than minor because it is associated with the Mitigating Systems Cornerstone attribute of equipment performance and affects the associated Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors conducted a Phase 1 screening of the finding in accordance with IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," and determined that the finding was of very low safety significance (Green) since it was not a design or qualification deficiency confirmed not to result in a loss of operability, did not result in a loss of system safety function, did not represent actual loss of safety function of a single train for greater than its Technical Specification allowed outage time, did not represent an actual loss of safety function of one or more non-Technical Specification trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours and was not risk significant due to seismic, flooding, or severe weather initiating events.

This cause of this finding had a cross-cutting aspect in the area of Human Performance in that personnel failed to follow the established procedure.

Enforcement: TS 6.4, "Procedures," Section A requires that, "Written procedures shall be established, implemented, and maintained covering the following activities ... surveillance and testing requirements." Contrary to the above, on February 12, 2007, operators failed to follow the surveillance procedure for the EDG fuel oil transfer system. Specifically OP 4195, Section C, Step 8, requires the running EDG (the "A" EDG in this case) to be stopped once day tank level has decreased to less than or equal to 30 inches. Operators incorrectly interpreted this step and allowed the "A" EDG to continue to run. Additionally, Step 9.e requires operators to throttle the day tank inlet valve FO-14A in the closed direction to obtain a specified transfer pump discharge pressure. Rather than throttle valve FO-14A, the operators incorrectly throttled the day tank outlet valve, FO-40A. When the operators did not see the expected fuel transfer system response, they continued to throttle FO-40A until the valve was fully closed. Once valve FO-40A was closed, the fuel oil supply to the "A" EDG was isolated causing the diesel to automatically trip and ultimately resulted in the accrual of 6.5 hours of "A" EDG unavailability. Because the finding was of very low safety significance and has been entered into Entergy's corrective action program, this violation is being treated as an NCV consistent with Section VI.A. of the NRC Enforcement Policy. NCV 05000271/2007002-03, Failure to Follow Procedure Results in Unplanned "A" Emergency Diesel Generator Shutdown and Unavailability.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope (one sample)

The inspectors observed a January 10, 2007, emergency preparedness (EP) practice drill and the subsequent player and lead controller critiques. Entergy preselected the drill notifications and protective action recommendations to be included in the EP drill performance indicator (PI). The inspectors discussed the performance expectations and results with Entergy's EP staff to confirm correct implementation of the PI program. The inspectors focused on the ability of licensed operators to perform event classifications and make proper notifications in accordance with the following station procedures and industry guidance:

- AP 0153, "Operations Department Communications and Log Maintenance;"
- AP 0156, "Notification of Significant Events;"
- AP 3125, "Emergency Plan Classification and Action Level Scheme;"
- DP 0093, "Emergency Planning Data Management;"
- OP 3540, "Control Room Actions During an Emergency;" and
- Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 4.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03)

a. Inspection Scope (nine samples)

The inspectors evaluated the operability and accuracy of radiation monitoring instrumentation and the adequacy of the respiratory protection program for issuing self-contained breathing apparatus (SCBA) to emergency response personnel. Implementation of these programs was reviewed against the criteria contained in 10 CFR 20, applicable industry standards, and Entergy procedures.

The following activities were performed:

- The inspectors reviewed the UFSAR, Sections 9.2, “Liquid Radwaste System,” 9.3, “Solid Radwaste System,” and 9.4, “Gaseous Radwaste System,” to identify applicable radiation monitors associated with transient high radiation areas in the plant for review;
- The inspectors performed walkdowns of the radiation protection instrument issue area provided for the selection of portable instruments that were available for use for job coverage of radiologically significant areas; and
- The inspectors reviewed current calibration records and applicable calibration procedures for the following plant radiation monitors and portable instruments. In addition, the applicable calibrators utilized were reviewed for National Institute of Science and Technology standard traceability.

  <u>Plant Radiation Monitors</u>

  Main steam line radiation monitors;
  Transverse in-core probe room area radiation monitor;
  East and West refueling floor area radiation monitors;
  Spent fuel pool area radiation monitor;
  Reactor water clean up phase separator area radiation monitor;
  Reactor building ventilation and refueling area zone monitors;
  Reactor building duct north and south monitors;
  Containment air monitors;
  Steam jet air ejector gas monitors; and
  Augmented off gas area radiation monitors.

  <u>Portable Routine Procedure (RP) Instruments</u>

  Six electronic dosimeters;
  Five radiation survey instruments;
  Two extendable probe survey instruments;
  Two continuous air monitors;
  Two air samplers;
  One personal lapel air sampler;
  One high purity germanium gamma detector; and
  Three beta and alpha air sample counters.

  <u>Calibrators</u>

  Shepherd 89 survey instrument calibrator; and
  Technical operations 682 instrument calibrator.

- The inspectors reviewed the corrective action program for CRs issued in 2006 that documented radiological incidents involving internal exposures. In addition, dosimetry electronic records were queried for any internal exposures greater than 50 mrem committed effective dose equivalent;

- CRs were reviewed with respect to radiation monitoring instrument deficiencies to determine if the deficiencies were appropriately characterized and corrected commensurate with their safety significance;
- CRs were reviewed to identify repetitive deficiencies;
- Portable instrument calibration expiration and response check stickers were reviewed. The applicable response check beta-source and instrument sign-out procedures were also reviewed;
- SCBA equipment and individual SCBA qualification records were reviewed against the requirements of Vermont Yankee Emergency Plan documents, (ENPL-140 & OPF 3506). This included inspection of selected SCBAs in the main control room, administration building hallway, alternate brigade room, and turbine building decon booth. Selected SCBA qualification records for on-shift reactor operators, radiation protection duty watch technicians, and chemistry duty watch technicians were verified for currency; and
- Selected SCBA units in the main control room were examined for periodic air cylinder hydrostatic testing and maintenance records. Review of approved replacement parts documentation and certification of the repair personnel was also performed.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope (three samples)

The inspectors sampled Entergy submittals for the PIs listed below for the period from January 2006 to December 2006. The inspectors reviewed selected operator logs, plant process computer data, and CRs and discussed the PI data with Entergy work planning and operations personnel. The PI definitions and guidance contained in NEI 99-02, “Regulatory Assessment Indicator Guideline,” and AP 0094, “NRC Performance Indicator Reporting,” were used to verify the accuracy and completeness of the PI data reported during this period.

Initiating Events Cornerstone

- Unplanned Power Changes per 7000 Critical Hours;
- Unplanned Scrams per 7000 Critical Hours; and
- Scrams with Loss of Normal Heat Removal.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Review of Items Entered into the Corrective Action Program

a. Inspection Scope

The inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into Entergy's corrective action program at an appropriate threshold and that adequate attention was being given to timely corrective actions. Additionally, in order to identify repetitive equipment failures and/or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into Entergy's corrective action program. This review was accomplished by reviewing the description of each new CR and/or by attending daily CR screening meetings. A listing of CRs reviewed is included in the attachment to this report.

b. Assessments and Observations

No findings of significance were identified.

.2 Annual Sample Review - Operator Workarounds

a. Inspection Scope (one sample)

The inspectors reviewed the cumulative effect of operator workarounds, operator burdens, and control room deficiencies on the reliability, availability, and potential mis-operation of systems with particular focus on issues that had the potential to affect the ability of operators to respond to plant transients and events. The inspectors reviewed the Operator Aggregate Impact Index and Operations Performance Indicators for January, February, and March 2007. Additionally, the inspectors reviewed Entergy tracking systems for operator burdens, control room deficiencies, system lineup deviations, and disabled or illuminated control room alarms. For selected issues, the inspectors reviewed CRs and discussed the issues with responsible operations personnel to ensure they were appropriately categorized and tracked for resolution. In addition, control panel and in-plant walkdowns were performed to identify any potential workarounds that had not been previously identified in accordance with procedures DP 0166, "Operations Department Standards," and AP 0047, "Work Requests."

b. Findings and Observations

No findings of significance were identified. The inspectors found that Entergy ensured appropriate attention was placed on conditions that could impact operator actions, including conditions that would require compensatory actions (e.g., workarounds and burdens), control room deficiencies and alarms, components tagged out-of-service or with caution tags, and component deviations. Corrective actions assigned to address these issues were appropriately scheduled for completion commensurate with each item's significance.

4OA3 Event Followup (71153)

.1 Plant Response to a Fire in the Motor Compartment of the South Vehicle Barrier

a. Inspection Scope (one sample)

The inspectors reviewed actions taken by Entergy in response to a January 18, 2007, fire in the motor compartment of the South vehicle barrier gate. This vehicle barrier gate is located outside of the protected area. The inspectors observed the response of control room and fire brigade personnel and evaluated their response against applicable operating procedures, abnormal operating procedures, and Emergency Plan emergency action level (EAL) procedures.

b. Findings

No findings of significance were identified.

.2 Plant Response to the Identification of a Potentially Degraded HPCI System Flow Controller

a. Inspection Scope (one sample)

The inspectors reviewed actions taken by Entergy in response to the identification of a potentially degraded HPCI system flow controller on January 24, 2007. Control room operators had observed the HPCI controller flow indication reading greater than 200 gallons per minute (gpm) with the pump in a standby lineup. Operators were concerned that the indication anomaly could affect controller performance under accident conditions. As a result, the HPCI system was declared inoperable and Entergy made an 8-hour notification to the NRC in accordance with 10 CFR 50.72. The inspectors discussed the controller issue with Operations and Engineering Department personnel. The inspectors observed the response of control room operators and evaluated their response against applicable operating procedures, TS requirements, UFSAR system description, abnormal operating procedures, and emergency plan EAL procedures. The inspectors reviewed the notification made by operators to the NRC and compared it to the reportability requirements of 10 CFR 50.72. Finally, the inspectors reviewed Entergy's subsequent retraction of the event notification to ensure the discussion supported the continued operability of the HPCI controller despite the observed flow indication anomaly.

b. Findings

No findings of significance were identified.

.3 Plant Response to an Unanticipated Loss of a 345 Kilovolt Off-Site Power Line

a. Inspection Scope (one sample)

The inspectors reviewed actions taken by plant personnel in response to a March 24, 2007, unanticipated loss of one of three 345 kilovolt (kV) offsite power lines that also resulted in the need to perform a reactor power reduction in order to meet grid stability limits. The inspectors discussed the event with control room operators and Entergy management. The inspectors reviewed control room logs, reviewed plant computer data, and performed a walkdown of the 345 kV and 115 kV switchyards. The inspectors also assessed the response of licensed operators during the power reduction against applicable operating procedures, abnormal operating procedures, and Emergency Plan EAL procedures.

b. Findings

Introduction: A self-revealing finding of very low safety significance (Green) was identified due to a procedure performance error made by Entergy Electrical Maintenance Department technicians while performing switchyard testing. As a result, one of three 345 kV offsite power lines and one of two 115 kV power supplies to the startup transformers were inadvertently isolated. The resultant switchyard breaker configuration required control room operators to reduce reactor power to approximately 65 percent to meet grid stability limits.

Description: On March 24, 2007, with the plant operating at full power, Entergy Electrical Maintenance Department Technicians were performing functional testing of 345 kV offsite power line 379 relays in accordance with Vermont Yankee RP 5258, "379 Line Functional Testing." Step 1.202 of RP 5258 required one technician to open four slide links associated with 345 kV offsite power line 381 and a second technician to verify the correct slide links had been opened. Both technicians signed the procedure indicating that the correct four slide links had been opened. Step 1.203 then directed technicians to simulate a North bus differential trip. When the technicians simulated the North bus differential trip, it resulted in an unanticipated actual trip of 345 kV circuit breaker 81-1T, 115 kV circuit breaker K-1, and the terminal breakers for the main 381 line circuit breaker. As a result, power was isolated to the 381 line (one of three 345 kV off-site power lines) and one of two 115 kV power supplies to the startup transformers.

Control room operators immediately noted the unanticipated response of these circuit breakers. At the same time, Independent System Operator (ISO) New England noted the loss of the 381 line and contacted the control room and notified the operators of the need to perform a power reduction in order to meet grid stability limits. Operators entered Vermont Yankee Off-Normal Procedure (ON) 3179, "Grid Stability," and reduced power to approximately 65 percent. The operators also entered ON 3155, "Loss of Auto Transformer," and TS Limiting Condition for Operation 3.10.B.3.a due to one of two 115 kV power supplies having been isolated to the startup transformers.

During their investigation, Entergy determined that the unanticipated breaker isolations occurred because the technicians failed to open one of the four slide links listed in Step 1.202 of RP 5258. Rather than opening slide links on terminals 3, 4, 5, and 8, the technicians opened slide links on terminals 3, 4, 5, and 9. This error was made despite the fact that the procedure required a concurrent verification (i.e., both technicians were required to identify the correct component before manipulating it) be performed. When the technicians subsequently simulated a North bus differential trip with slide link 8 closed, the protection system responded as if there were an actual differential trip ultimately resulting in the tripping of circuit breakers 81-1T, K-1, and the 381 line terminal breakers. Entergy entered this issue into their corrective action program (CR 2007-0898).

Analysis: The performance deficiency associated with this finding was the failure of Electrical Maintenance Department technicians to follow the procedural requirements of RP 5258. Rather than opening slide links on terminals 3, 4, 5, and 8, the technicians opened slide links on terminals 3, 4, 5, and 9. As a result, one of three 345 kV offsite power lines and one of two 115 kV power supplies to the startup transformers were inadvertently isolated. The resultant switchyard breaker configuration required control room operators to reduce reactor power to approximately 65 percent to meet grid stability limits. The finding is more than minor because it is associated with the Equipment Performance-Maintenance attribute of the Initiating Events Cornerstone and affected the associated cornerstone objective of limiting the likelihood of those events that upset plant stability (i.e., performance of a reactor power reduction). The inspectors conducted a Phase 1 screening of the finding in accordance with IMC 0609, Appendix A, “Determining the Significance of Reactor Inspection Findings for At-Power Situations.” The finding was determined to be of very low safety significance (Green) because performing the reactor power reduction did not increase the likelihood of both a reactor trip and the unavailability of mitigating equipment. Because this finding does not involve a violation of regulatory requirements and has very low safety significance, it is identified as FIN 05000271/2007002-04, Error Made by Electrical Maintenance Department Technicians Results in the Need for a Reactor Power Reduction.

The inspectors determined that the cause of this finding was related to the cross-cutting area of Human Performance. Electrical Maintenance Department technicians failed to follow procedure RP 5258.

Enforcement: No violation of NRC regulatory requirements was identified. Although Electrical Maintenance Department technicians failed to follow procedure RP 5258, testing performed on switchyard equipment (i.e., non-safety equipment) does not fall under NRC regulatory requirements.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On April 10, 2007, the resident inspectors presented the inspection results to Messrs. Theodore Sullivan, William Maguire, and members of the VY staff. On April 23, 2007, the resident inspectors discussed the results of their review of the “A” SW pump packing extrusion event with Mr. Chris Wamser (acting General Manager) and members of the VY staff. The inspectors asked whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

ATTACHMENT

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Entergy Personnel

J. Dreyfuss, Director of Nuclear Safety
M. Hamer, Licensing
E. Harms, Operations Manager
W. Maguire, General Manager of Plant Operations
D. Mannai, Licensing Manager
K. Pushee, Radiation Protection Manager
N. Rademacher, Director of Engineering
T. Sullivan, Site Vice President
C. Wamser, Work Planning and Outage Scheduling Manager
M. Wilson, Emergency Preparedness Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000271/2007002-01	FIN	Failure to Establish Minimum Thread Engagement for the "A" SW Pump Packing Gland Studs Results in Unplanned Unavailability (Section 1R12)
05000271/2007002-02	NCV	Inadequate Design Control Associated with CST Vortexing Analysis (Section 1R15)
05000271/2007002-03	NCV	Failure to Follow Procedure Results in Unplanned "A" Emergency Diesel Generator Shutdown and Unavailability (Section 1R22)
05000271/2007002-04	FIN	Error Made by Electrical Maintenance Department Technicians Results in the Need for a Reactor Power Reduction (Section 4OA3.3)

LIST OF DOCUMENTS REVIEWED

Section 1R04.2: Complete Equipment Alignment

Procedures
OP 2115, Primary Containment
OP 4202, Primary Containment Vacuum Breaker Inspection and Testing

Drawings
G191175, Sheet 1, Primary Containment and Atmosphere Control System

Condition Reports
CR 2001-1245
CR 2001-1665
CR 2002-2733
CR 2004-2232
CR 2004-3243
CR 2005-3364
CR 2006-0616
CR 2006-1122
CR 2006-2661

Miscellaneous Documents
Licensed Operator Training Lesson Plan 223, Primary Containment Design
Design Basis Document for the Containment Pressure Suppression System
Vermont Yankee 10 CFR 50.65 Maintenance Rule Scoping Basis Document for Primary Containment Atmosphere Control

Section 1R12: Maintenance Effectiveness

Procedures
AP 0021, Work Orders
DP 0216, Maintenance Department Routine Inspections
OP 0212, General Bolting Guidelines
EN-MA-101, Conduct of Maintenance
EN-WM-105, Planning

Condition Reports
CR 1996-1157
CR 2004-2002
CR 2006-1549
CR 2007-1151
CR 2007-0652

Training Lesson Plans
MMC-03-002, Fasteners and Torque Requirements

Miscellaneous Documents
Control Room Operator Logs
Tom-Pac Packing Manufacturer Installation Instructions
Work Order 00102744-01, Replace Tom-Pac Packing ["A" SW pump]

Section 1R17: Permanent Plant Modifications

Drawings
B-191261, Vermont Yankee Manometer Hook-up to Instrument Racks
5920-3012, Instrument Rack 25-5 Arrangement
5920-3919, Instrument Rack 25-6 Arrangement
5920-3053, Instrument Rack 25-51 Arrangement
5920-3058, Instrument Rack 25-52 Arrangement

Condition Reports
CR 2007-0495

Miscellaneous Documents
Engineering Design Change Request (EDCR) 79-02, Installation of Analog Trip System
EDCR 82-08, Analog Upgrade to Primary Instrumentation
EDCR 95-403, Recirculation Flow test Tank Installation

Section 2OS3: Radiation Monitoring Instrumentation and Protective Equipment

Condition Reports
CR 2007-0098
CR 2007-0106
CR 2007-0665

Section 4OA2.1: Review of Items Entered into the Corrective Action Program
CR 2006-1750
CR 2006-3457
CR 2006-3484
CR 2007-0012
CR 2007-0018
CR 2007-0019
CR 2007-0088
CR 2007-0098
CR 2007-0116
CR 2007-0117
CR 2007-0132
CR 2007-0141
CR 2007-0142
CR 2007-0151
CR 2007-0152
CR 2007-0170
CR 2007-0173
CR 2007-0190
CR 2007-0251
CR 2007-0292
CR 2007-0313
CR 2007-0318
CR 2007-0324
CR 2007-0334
CR 2007-0369
CR 2007-0474
CR 2007-0483
CR 2007-0495
CR 2007-0536
CR 2007-0556
CR 2007-0567
CR 2007-0570
CR 2007-0571
CR 2007-0601

CR 2007-0652
CR 2007-0794
CR 2007-0898
CR 2007-0899

Section 4OA2.2: Annual Sample Review - Operator Workarounds

Procedures
AP 0047, Work Requests
DP 0166, Operations Department Standards

Condition Reports
CR 2004-1950
CR 2005-1870
CR 2006-1491
CR 2006-1496
CR 2006-2569
CR 2006-2717
CR 2007-0371

Work Orders
WO 2004-2550, Replace reactor building pressure transmitter PT-1-125-3B-4
WO 51069238, Repair reactor water cleanup system (RWCU) valve V20-556
WO 51081656, Repair RCIC system gland seal vacuum pump control switch
WO 51080679, Repair RHR system pump discharge check valve V10-48B
WO 510805597, Repair steam trap MS-107-1A
WO 51074816, Replace standby gas treatment (SBGT) system pressure transmitters
WO 51079608, Replace position indication for control rod 26-07

Miscellaneous Documents
Management Review Meeting minutes for January, February, and March, 2007
Vermont Yankee Operations Department Aggregate Impact Index
System Health Reports for the RHR, RWCU, RCIC, and SBGT systems

Section 4OA3.1: Plant Response to a Fire in the Control Panel for the South Vehicle Barrier

Procedures
OP 3020, Fire Emergency Response Procedures

Condition Reports
CR 2007-0187
CR 2007-0318

Section 4OA3.2: Plant Response to the Identification of a Potentially Degraded HPCI System Flow Controller

Procedures
OP 2120, High Pressure Coolant Injection System

Condition Reports
CR 2007-0230

Miscellaneous Documents
Apparent Cause Evaluation, HPCI Flow Indicator Reading Out of Spec
HPCI System Design Basis Document
Event Notification Worksheet 43113, The HPCI flow control loop was found degraded in such a manner that HPCI would not perform its design safety functions, dated 01/22/07
Event Notification 43113 Retraction dated 3/9/07

LIST OF ACRONYMS

ACE	apparent cause evaluation
ACS	alternate cooling system
ADAMS	agencywide documents access and management system
AP	Vermont Yankee administrative procedure
ASME	American Society of Mechanical Engineers
CFR	code of federal regulations
CR	condition report
CS	core spray
CST	condensate storage tank
DP	Vermont Yankee department procedure
EAL	emergency action level
EDCR	engineering design change record
EDG	emergency diesel generator
EP	emergency preparedness
FA	fire area
FIN	finding
FZ	fire zone
gpm	gallons per minute
HPCI	high pressure coolant injection
IMC	inspection manual chapter
IPEEE	individual plant examination external events
IR	inspection report
ISO	independent service operator
Kv	kilovolt
LOCA	loss of coolant accident
mrem	millerem
NCV	non-cited violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission

OE	operating experience
ON	off-normal procedures
OP	Vermont Yankee operating procedure
PARS	publicly available records
PI	performance indicator
PMT	post maintenance testing
RCIC	reactor core isolation cooling
RHR	residual heat removal
RP	routine procedure
RWCU	reactor water cleanup
SBGT	standby gas treatment
SCBA	self-contained breathing apparatus
SDP	significance determination program
SPAR	standardized plant analysis risk
SRA	senior reactor analyst
SW	service water
TS	technical specification
UFSAR	Updated Final Safety Analysis Report
VYC	Vermont Yankee calculation
VY	Vermont Yankee
WO	work order