December 2, 2004

Mr. Jay K. Thayer
Site Vice President
Entergy Nuclear Operations, Inc.
Vermont Yankee Nuclear Power Station
P.O. Box 0500
185 Old Ferry Road
Brattleboro, VT 05302-0500

SUBJECT: VERMONT YANKEE NUCLEAR POWER STATION
NRC INSPECTION REPORT 05000271/2004008

Dear Mr. Thayer:

On September 3, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at the Vermont Yankee Nuclear Power Station. The enclosed inspection report documents the inspection findings, which were discussed with members of your staff on September 3, October 27, and November 23, 2004.

The 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. In conducting the inspection, the team examined the adequacy of selected components and operator actions to mitigate postulated design basis accidents, both under current licensing and planned power uprated conditions. The inspection also reviewed Entergy's response to selected operating experience issues, and assessed the adequacy of Vermont Yankee's design and engineering processes.

The team concluded that the components and systems reviewed would be capable of performing their intended safety functions. The team also concluded that sufficient design controls had been implemented for design and engineering work, including that related to Entergy's extended power uprate. The team did identify several deficiencies related to design control at Vermont Yankee; however, sample based extent-of-condition reviews indicated the original problems were not widespread or programmatic in nature. In addition, some of the specific findings included topics that were within the scope of the NRC's power uprate review, and thus, will require the submittal of additional information to the NRC's technical staff to support that review.

The enclosed report documents eight findings of very low safety significance (Green), all of which were determined to involve a violation of NRC requirements. Because of their very low safety significance and because the findings were entered into your corrective action program, the NRC is treating them as non-cited violations (NCVs), consistent with Section VI.A of the NRC's Enforcement Policy. If you contest these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the 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,

United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the 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 NRC's document system (ADAMS). ADAMS is temporarily unavailable due to an ongoing security review; therefore, this document will also be posted on the NRC Web site at http:\\www.nrc.gov\reactors\plant-specific-items\vermont-yankee-issues.html.

Sincerely,

/RA/

Wayne D. Lanning, Director
Division of Reactor Safety

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

Enclosure: Inspection Report 05000271/2004008 w/Attachments

cc w/encl:
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J. T. Herron, Senior Vice President and Chief Operating Officer
D. L. Pace, Vice President, Engineering
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-271
License No.	DPR-28
Report No.	05000271/2004008
Licensee:	Entergy Nuclear Vermont Yankee, LLC
Facility:	Vermont Yankee Nuclear Power Station
Location:	320 Governor Hunt Road Vernon, Vermont 05354-9766
Dates:	August 9 - 20 and August 30 - September 3, 2004
Inspectors:	J. Jacobson, Team Leader, Inspection Program Branch, NRR F. Bower, Senior Reactor Inspector, DRS, Region I G. Bowman, Reactor Inspector, DRS, Region I S. Dennis, Senior Operations Engineer, DRS, Region I M. Snell, Reactor Engineer, DRP, Region I C. Baron, NRC Contractor S. Spiegelman, NRC Contractor G. Skinner, NRC Contractor
Observer:	W. Sherman, Vermont State Nuclear Engineer
Approved by:	Wayne D. Lanning, Director Division of Reactor Safety Region I

Enclosure

CONTENTS

EXECUTIVE SUMMARY

During the period from August 9 through September 3, 2004, the US Nuclear Regulatory Commission (NRC) conducted a team inspection in accordance with Temporary Instruction 2515/158, "Functional Review of Low Margin/Risk Significant Components and Human Actions," at the Vermont Yankee Nuclear Power Station. The team was comprised of eight inspectors, including a team leader from the NRC's Office of Nuclear Reactor Regulation, four inspectors from the NRC's Region I Office, and three contractors. All of the inspectors and contractors met strict independence criteria developed for this inspection. Specifically, the NRC inspectors had not performed engineering inspections at Vermont Yankee within the last two years and had not been assigned as resident inspectors at Vermont Yankee. The contractors had never been directly employed by Entergy or Vermont Yankee, had not performed contract work for Entergy or Vermont Yankee in the past two years, and had not performed inspections for the NRC at Vermont Yankee within the past two years. The inspection was the first of four planned pilot inspections to be conducted throughout the country to assist the NRC in determining whether changes should be made to its Reactor Oversight Process (ROP) to improve the effectiveness of its inspections and oversight in the design/engineering area.

In selecting samples for review, the team focused on those components and operator actions that contribute the greatest risk to an accident that could involve damage to the reactor core. Additional consideration was given to those components and operator actions impacted by the licensee's request for a 20 percent extended power uprate (EPU) license amendment. The team focused its reviews on those components and operator actions contained in the reactor core isolation cooling (RCIC), main feedwater, safety relief valve, onsite electrical power, and off-site electrical power systems. In addition, inspection samples were added based upon operational experience and issues previously identified by the NRC's technical staff during the course of their reviews associated with the licensee's request for an EPU. A complete listing of all components, operator actions, and operating experience issues reviewed by the inspection team is contained in Attachment A to this report.

For each sample selected, the team reviewed design calculations, corrective action reports, maintenance and modification histories, associated operating procedures, and performed walkdowns of material conditions (as practical). The team concluded that the components and systems reviewed would be capable of performing their intended safety functions. The team also concluded that sufficient design controls had been implemented for engineering work, including that related to Entergy's EPU. The overall material condition of the plant and of the specific components reviewed was also noted as being good. The team identified eight findings of very low safety significance, one unresolved item, and one minor finding. The eight findings are listed in the "Summary of Findings" section of this report.

The team assessed the safety significance of each of the findings using the NRC's Significance Determination Process (SDP). Using this process, each of the findings was determined to be of very low safety significance. Also, for each of the findings where current operability was in question, the licensee provided a basis for operability and entered the issue into their corrective action program, as necessary to complete a more comprehensive assessment of the issue, including any programmatic oversight weaknesses that might have prevented self-identification. In addition, for the findings associated with a design vulnerability of an RCIC pressure control valve, the control of the condensate storage tank (CST) temperature to the limits of transient

analysis assumptions, and the updating of the Safe Shutdown Capability Analysis, the team performed sample-based extent-of-condition reviews during the inspection to determine the breadth of the issues identified. No additional findings were identified during these reviews, indicating the original problems identified were not widespread, and were likely not programmatic in nature. Additional licensee extent-of-condition reviews of the issues were ongoing at the conclusion of the inspection.

Some of the findings also concern topics that are within the scope of the NRC's power uprate review and therefore will require the submittal of additional information to the NRC's technical staff.

SUMMARY OF FINDINGS

IR 05000271/2004008; 08/09/2004-09/03/2004; Vermont Yankee Nuclear Generating Station; Functional Review of Low Margin/Risk Significant Components and Human Actions.

This inspection was conducted by five inspectors and three NRC contractors. Eight Green non-cited violations, one unresolved item, and one minor finding were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process." Findings for which the SDP does not apply may be "Green" or be assigned a severity level after 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 Findings

Cornerstone: Mitigating Systems

- Green. The team identified a non-cited violation of 10 CFR Part 50.63, "Loss of All Alternating Current Power," because the licensee had not completed a coping analysis for the period of time the alternate alternating current (AC) source (the Vernon Hydro-Electric Station) would be unavailable and had not demonstrated by test the time required to make the alternate source available for a station blackout involving a grid collapse. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a station blackout. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Specifically, the team found that the licensee's preliminary coping analysis, performed during the inspection, demonstrated a four-hour coping time which should be sufficient to envelope the time required to start and align the Vernon Station. (Section 4OA5.2.1.1)

- Green. The team identified a non-cited violation of Technical Specifications 6.4.C, "Procedures," because the licensee failed to establish adequate procedures for determining the operability of the 115 kilovolt (kV) Keene line, which is designated as an alternate immediate access power source if the 345/115 kV auto transformer is lost. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Procedural Quality and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a loss of off-site power. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Specifically, the team did not identify any instances where the lack of procedural guidance had resulted in an inadequate assessment of off-site power operability or the inoperability of the electrical system or any components. (Section 4OA5.2.1.1)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” because the licensee used incorrect and non-conservative voltage values in calculations performed to assure that electrical equipment would remain operable under degraded voltage conditions. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a design basis accident. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Specifically, the team did not identify any instances where using the Technical Specification degraded voltage allowable setpoint values would have resulted in inoperable equipment. (Section 4OA5.2.1.1)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” because the licensee did not implement measures to ensure that the design basis for the cooling water supply to the lube oil cooler of RCIC was correctly translated into the specifications, drawings, procedures, or instructions. Specifically, the installed pressure control valve in the lube oil cooler water supply line was not independent of air systems, and the installed piping between the pressure control valve and lube oil cooler did not contain a restricting orifice. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the reliability of the RCIC system. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. This deficiency would not have resulted in the RCIC system becoming inoperable due to a loss of air to the lube oil cooler pressure control valve. (Section 4OA5.2.1.2).

  A contributing cause of this finding is related to the cross cutting area of Problem Identification and Resolution. The licensee had previously reviewed the failure positions of air-operated equipment and issued a report, “Compressed Air Systems,” dated July 16, 1989. During this review, the licensee did not identify that the pressure control valve was not independent of the instrument air system.

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” because the licensee failed to correct a longstanding non-conformance in the operation of pressure control valve PCV-13-23. The team determined through interviews with Vermont Yankee staff that during initial start-up testing, problems were identified with the automatic operation of this valve which affected its ability to properly supply cooling flow to the RCIC lube oil cooler. This issue was more than minor because it was associated with the Mitigating Systems attribute of Equipment Performance and affected the cornerstone objective of ensuring the reliability of the RCIC system. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. The licensee had implemented manual actions as a compensatory

measure for the operation of PCV-13-23 through the addition of procedural steps. (Section 4OA5.2.1.2)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because the licensee had neither established the correct condensate storage tank (CST) temperature limit for use in the plant transient analyses nor translated the CST temperature limit into plant procedures. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the reliability of the core spray system. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Although available net positive suction head (NPSH) margin for the core spray pumps was lowered, adequate margin remained due to the conservatism that existed in other aspects of the licensee's NPSH analysis. (Section 4OA5.2.1.7)

  A contributing cause of this finding is also related to the cross-cutting area of Problem Identification and Resolution. The licensee identified this issue in December 2002, but concluded that the non-conservative CST temperature had little to no effect on the transient analyses.

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because between June 2001 to September 2004, the licensee did not adequately coordinate between the operations department and the engineering organization regarding procedure revisions that increased the length of time required to place the reactor core isolation cooling system in service from the alternate shutdown panels. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Human Performance and affected the cornerstone objective of ensuring the availability of the RCIC system. Furthermore, this finding resulted in the use of the December 1999 value of time to place RCIC in service from the alternate shutdown panel in documents submitted to the NRC as part of the Vermont Yankee Power Uprate Safety Analysis Report. The issue screened as very low safety significance in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Although the available time margin was lowered, sufficient margin remained to allow operator action to manually start the RCIC system prior to reactor level reaching the top of active fuel. (Section 4OA5.2.2)

- Green. The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," because the licensee had conducted motor-operated valve (MOV) diagnostic tests using procedures that did not include acceptance limits, which were correlated to and based on applicable (stem thrust and torque) design documents. Additionally, MOV diagnostic testing had been conducted solely from the motor control centers using test instrumentation that had not been validated to ensure its adequacy. The finding was more than minor because it affected the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the availability,

reliability, and capability of systems and components that respond to initiating events. Specifically, the unvalidated test method had the potential to affect the reliability of safety-related motor-operated valves. The issue screened as very low safety significance in Phase I of the SDP because it was a qualification deficiency that was not found to result in a loss of function. The team did not identify any examples of degraded or inoperable valves during the inspection and noted that the design basis calculations for the MOVs reviewed had available thrust margin of greater than 60 percent. (Section 4OA5.2.3)

B. Licensee Identified Violations

None.

REPORT DETAILS

4OA2 Problem Identification and Resolution (PI&R)

2. Annual Sample Review

Not applicable.

3. Cross Reference to PI&R Findings Documented Elsewhere

Section 2.1.2 (b) 1 of this report describes a finding associated with a design vulnerability of the reactor core isolation cooling (RCIC) system lube oil cooling pressure control valve in that the valve design was not independent of station service air as described in the Updated Final Safety Analysis Report. The licensee had previously reviewed the failure positions of air-operated equipment and issued a report, “Compressed Air Systems,” dated July 16, 1989. This longstanding deficiency was not identified by this review or by other station service air reviews.

Section 2.1.7 (b) of this report describes a finding associated with maintaining the condensate storage tank temperature within limits assumed in the facility’s transient analysis. The licensee had identified conditions where the tank temperature had exceeded the transient analysis assumptions but had not taken sufficient corrective actions.

4OA5 Other Activities - Temporary Instruction 2515/158

1. Inspection Sample Selection Process

In selecting samples for review, the team focused on the most risk-significant components and operator actions. The team selected these components and operator actions by using the risk information contained in the licensee’s Probabilistic Risk Assessment (PRA) and the US Nuclear Regulatory Commission’s (NRC’s) Simplified Plant Analysis Risk (SPAR) models. An initial sample was chosen from those components and operator actions that had a risk achievement worth factor greater than two. These components and operator actions are important to safety since their assumed failure would result in at least doubling the risk of an accident that could result in core damage. Consideration was also given to those components and operator actions most impacted by the licensee’s request for a 20 percent extended power uprate (EPU) license amendment.

Many of the samples selected were located within the reactor core isolation cooling, main feedwater, safety relief valve, onsite electrical power, and off-site electrical power systems. In addition, inspection samples were added based upon operational experience reviews. The team was also briefed by the NRC’s technical staff conducting the EPU licensing review on issues that had arisen during their reviews, indicating areas that might warrant additional inspection. A complete listing of all components, operator actions and operating experience issues reviewed by the inspection team is contained in Attachment A to this report. A total of 91 samples were chosen for the team’s initial review.

A preliminary review was performed on the 91 samples to determine whether any low-margin concerns existed. For the purpose of this inspection, margin concerns included original design issues, margin reductions due to the proposed EPU or margin reductions identified as a result of material condition issues. Consideration was also given to the uniqueness and complexity of the design, operating experience, and the available defense-in-depth margins. Based upon the above considerations, 45 of the original 91 samples were selected for a more detailed review. An overall summary of the reviews performed and the specific inspection findings identified is included in the following sections of the report.

2. Results of Detailed Reviews

The team performed detailed reviews on the 45 components, operator actions and operating experience issues. For components, the team reviewed the adequacy of the original design, modifications to the original design, maintenance and corrective action program histories, and associated operating and surveillance procedures. As practical, the team also performed walkdowns of the selected components. For operator actions, the team reviewed the adequacy of operating procedures and compared design basis time requirements against actual demonstrated timelines. For the operating experience issues chosen for detailed review, the team assessed the issues' applicability to Vermont Yankee and the licensee's disposition of the issue. The following sections of the report provide a summary of the detailed reviews, including any findings identified by the inspection team.

2.1 Detailed Component and System Reviews

2.1.1 Electrical Power Sources

a. Inspection Scope

The team reviewed the adequacy of the onsite and off-site electrical power sources that supply power to the safety-related components chosen for detailed review. Particular focus was paid to the off-site power sources and grid stability, to the extent they would be impacted by an EPU. The team's review encompassed the licensee's plans to limit the initial power increase to 15 percent, as a capacitor bank necessary to provide reactive power to the grid to ensure stability had yet to be installed. Other attributes of the electrical systems reviewed during the inspection were operating procedures, setpoints for degraded voltage relays, battery capacity, circuit breaker coordination, fast and slow transfer schemes, Technical Specifications (TS) and other related calculations.

The team conducted a walkdown of the safety-related switchgear rooms and the electrical controls in the main control room with station engineering personnel. The review was conducted to identify any alignment discrepancies or visible signs of significant deficient material conditions.

The team also performed a detailed, focused review of the ability of the Vernon Hydro-Electric Station to supply emergency power to Vermont Yankee in the event of a station blackout (SBO) caused by a grid disturbance, as required by 10 CFR Part 50.63, "Loss of all Alternating Current Power," and as clarified by Regulatory Guide 1.155, Station Blackout, and NUMARC 87-00, Revision 1. The team reviewed procedures associated with the operator actions necessary to tie in the Vernon Station, procedures associated with the operation and maintenance of the Vernon Station, and regional grid operator system restoration procedures. The team also visited the remote control location for the Vernon Station, and interviewed station personnel. Lastly, the team conducted a conference call with the regional grid operator responsible for controlling the operation of circuit breakers and switches in the Vernon switchyard.

b. Findings

(1) Availability of Power from Vernon Station

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50.63, "Loss of All Alternating Current Power," because the licensee had not completed a coping analysis and had not demonstrated, by test, the time required to make the alternate alternating current (AC) source available for an electrical grid collapse resulting in a station blackout.

Description. 10 CFR Part 50.63 requires that licensees be able to recover from an SBO that results from a loss of all AC electrical power (both the normal off-site power sources and the on-site emergency diesel generators). In Section C.2, "Offsite Power," Regulatory Guide 1.155 defines the minimum potential causes to be considered for a loss of off-site power that results in an SBO. One listed cause is grid undervoltage and collapse. For SBO scenarios where the licensee cannot demonstrate by test that an alternate AC source would be available within 10 minutes, 10 CFR Part 50.63 requires the licensee to complete a coping analysis for the period of time it would take for power to be restored.

At Vermont Yankee, the licensee credits the Vernon Hydro-Electric Station as its alternate AC source to respond to a station blackout within 10 minutes. If a grid collapse occurs, the Vernon Station would trip offline and have to be restarted. The Vernon Station is considered a "black start" facility by the regional grid operator. As such, the Vernon Station is required to certify it can be ready to supply power within 90 minutes after tripping off line. However, in order to supply power to Vermont Yankee under such conditions, the Vernon switchyard would have to be configured to isolate the Vernon Station from the rest of the grid. The operation of the circuit breakers necessary to complete such actions is not controlled by either the licensee or the Vernon Station, but is controlled by the regional grid operator. The team held a conference call with the grid operators. During the call, the team learned that no specific procedures or communication protocols had been set up to deal with a station blackout at Vermont Yankee. The only reference to Vermont Yankee was a general

statement in a procedure that said that nuclear generators should receive critical priority. During the call, the team also learned that the grid operator did not differentiate between situations where normal off-site power was lost to a nuclear unit but emergency diesels remain available, and those situations where the emergency diesel generators failed to start and the station was in a true blackout condition. The team learned that no specific training, testing, or simulations had been conducted to simulate the actions that would have to be taken to respond to an SBO at Vermont Yankee caused by a grid collapse.

As a result of the team's concerns, the licensee issued condition reports (CRs) CR-VTY-2004-2677 and 2004-2738. The licensee also created a preliminary timeline which estimated the time to restore power under such conditions as being between 20 minutes and 2 hours. The licensee also performed an operability evaluation in accordance with Generic Letter 91-18, which included a preliminary four-hour coping analysis. The licensee provided the team a copy of the preliminary coping analysis and copies of the original NRC Safety Evaluation Report (SER) for the station blackout rule dated September 1, 1992. The team reviewed the preliminary coping analysis and found the methodology used to be reasonable. Review of the NRC SER indicated that questions were asked by the NRC staff regarding a regional grid disturbance during the original station blackout review, and that the licensee's response was that power would be restored within one hour. Based upon the above facts, the team determined that the one hour time stated in the SER could no longer be ensured. Furthermore, contrary to 10 CFR Part 50.63, the licensee had not completed a coping analysis for the period of time it would take to restore the alternate source.

<u>Analysis</u>. The team determined that this issue was a performance deficiency since the licensee had not demonstrated by test that the Vernon Station could supply power to Vermont Yankee within one hour after the onset of a station blackout and had not completed a coping analysis for the period of time the Vernon Station would be unavailable, as required by 10 CFR Part 50.63. Also, the licensee did not remain cognizant of how design changes, made by the operator of the Vernon Station, affected the ability of the Vernon Station to supply emergency power to Vermont Yankee in a timely manner. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a station blackout resulting from a grid collapse. The issue screened as very low safety significance (Green) in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Specifically, the team found that the licensee's preliminary coping analysis, performed during the inspection, demonstrated a four-hour coping time that should be sufficient to envelope the time required to start and align the Vernon Station.

<u>Enforcement</u>. 10 CFR Part 50.63(c)(2), requires that a coping analysis be performed if the designated alternate AC source cannot be made available within 10 minutes. It also requires that the time required to make the alternate AC

source available be demonstrated by test. Contrary to the above, the licensee had not completed a coping analysis for the period of time the alternate AC source would be unavailable and had not demonstrated by test the time required to make the alternate source available for a station blackout involving a grid collapse. Because this finding is of very low safety significance and the licensee entered this issue into its corrective action program (CR-VTY-2004-2677 and 2004-2738), it is considered a non-cited violation consistent with Section VI.A.1 of the NRC's Enforcement Policy. **(NCV 05000271/2004008-01 Availability of Power from Vernon Station)**

(2) Procedures for Assessing Off-site Power Operability

Introduction. The team identified a Green non-cited violation of Technical Specifications 6.4, "Procedures," because the licensee did not establish adequate procedures for assessing the operability of the 115 kilovolt (kV) Keene line.

Description. At Vermont Yankee, the immediate access off-site power source is normally derived from the 345 kV switchyard through the 345/115 kV transformer T-4-1A. The 115 kV Keene line may also be conditionally used as an alternate immediate access source for satisfying TS requirements for off-site power supplies, depending on grid and plant conditions. Specifically, Technical Specification Bases 3.10.A, states that the availability of the Keene line is dependent on its pre-loading which must be limited by the system dispatchers prior to it being declared an immediate access source.

The team reviewed Procedure ON 3155, "Loss of Auto Transformer," and noted that Step 2b, instructs operators to contact ISO New England to determine the 115 kV Keene line load limit but does not provide explicit criteria for evaluating the line's operability. The team also noted Note 5 on the load nomograph included in procedure ON 3155, Reference D, "Guidelines for Operating the Vermont Yankee 115 kV System with the VTY4 Auto Transformer Out of Service," stated the assumption that, "All Vermont Yankee motor startups performed sequentially, not simultaneously." During accident loading with off-site power available, all safety loads are designed to block start simultaneously, so this assumption would never be met.

The team noted the procedure also contained invalid criteria for assessing the operability of the downstream safety buses. Step 11 allowed operation of bus 3 or 4 with voltages as low as 3600 volts (V) AC. This voltage was below the TS allowable setting of 3660 VAC for the degraded voltage relays. Under non-accident conditions, operation of the buses at this minimum voltage would result in automatic actuation of the degraded voltage relays, separating the buses from off-site power. Under post-accident conditions, the degraded voltage protection relays are locked out and operation of the buses at 3600 VAC could result in equipment mis-operation or damage.

Analysis. The team determined this to be a performance deficiency since the operating procedures did not provide adequate guidance for determining operability of the 115 kV Keene line. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Procedure Quality and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a loss of off-site power. The issue screened as very low safety significance (Green) in Phase I of the SDP because the failure to translate design requirements into operating procedures was a design deficiency that was not found to result in a loss of function. Specifically, the team did not identify any instances where the lack of procedural guidance had resulted in an inadequate assessment of off-site power operability or the inoperability of the electrical system or any components.

Enforcement. Technical Specifications 6.4.C, "Procedures," requires that written procedures be established, implemented, and maintained for actions to be taken to correct specific and unforeseen potential malfunctions of systems or components. Contrary to the above, the licensee did not establish adequate procedures for assessing the operability of the 115 kV Keene line. Since this finding is of very low safety significance and has been entered into the licensee's corrective action program (CR-VTY-2004-2803 and CR-VTY-2004-2804), it is considered a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000271/2004008-02 Procedures for Assessing Off-site Power Operability)**

(3) Degraded Voltage Relay Setpoint Calculations

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50 Appendix B, Criterion III, "Design Control," because the licensee did not use the Technical Specification allowed voltage value in the calculations used to ensure the degraded voltage relay dropout function would provide adequate voltage to safety-related electrical equipment.

Description. As described in Section 8.5 of the Vermont Yankee Updated Final Safety Analysis Report (UFSAR), the licensee has installed degraded voltage relays, which are designed to protect the station's electrical equipment from damage that could occur due to degraded voltage. The licensee's Technical Specifications (TS) allow a minimum degraded voltage relay setpoint of 3660 VAC; however, the licensee's analysis of record, VYC-1088 "Vermont Yankee 4160/480 Volt Short Circuit/ Voltage Study," did not evaluate the operability of the connected electrical components at this minimum TS value. Instead, the lowest voltage evaluated by VYC-1088 was based on the minimum expected switchyard voltages, which were 3951 VAC for bus 3 and 3809 VAC for bus 4. Consequently, motors were evaluated for voltage considerably above the minimum voltage that could occur based on the TS value.

As a result, calculation VYC-1053 and VYC-1314, which determine worst-case motor-operated valve (MOV) and motor control center (MCC) voltages, were also non-conservative. In response to the team's concerns, the licensee initiated CR-VTY-2004-2596. The operability determination (OD) for CR-VTY-2004-2596 identified two motors that did not meet calculation acceptance criteria and provided justification for their operability. This OD also provided justification for lower MCC control circuit voltages than previously analyzed. The licensee also initiated CR-VTY-2004-2734 to address the effects of the postulated lower voltage on MOV operation. The effect on the MOVs was not expected to be significant due to the otherwise generally conservative approach used for MOV calculations.

Analysis. The team determined this to be a performance deficiency because the licensee's calculations did not ensure the operability of electrical equipment at the minimum TS value for the degraded voltage relay dropout setting. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring availability, reliability, and capability of systems needed to respond to a design basis accident. The issue screened as very low safety significance (Green) in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. Specifically, the team did not identify any instances where using the Technical Specification degraded voltage allowable setpoint values would have resulted in inoperable equipment.

Enforcement. 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires that measures be established to assure that applicable regulatory requirements and the design basis for structures, systems and components are correctly translated into specifications, drawings, procedures and instructions. Contrary to the above, the licensee used incorrect and non-conservative voltage values in calculations performed to ensure that electrical equipment would remain operable under degraded voltage conditions. Since this finding is of very low safety significance and has been entered into the licensee's corrective action program (CR-VTY-2004-2596 and CR-VTY-2004-2734), it is considered a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000271/2004008-03 - Degraded Voltage Relay Setpoint Calculations)**

(4) Ungrounded 480 VAC Electrical System.

The team identified an unresolved item (URI) associated with the 480 VAC circuit-breakers designed to detect and interrupt electrical malfunctions. An unresolved item is an issue requiring further information to determine if it is acceptable, if it is a finding or if it constitutes a deviation or violation of NRC requirements. In this case, additional review will be required to determine if the facility is in accordance with its design and/or licensing basis, since this was part

of the original design of the facility. Also, additional review will be required to determine the safety significance of this issue.

The Vermont Yankee 480 VAC system consists of two 480 VAC load center buses supplied through separate 4160/480 V transformers from the redundant 4160 VAC safety buses. The transformers are connected delta-delta and the 480 VAC system is ungrounded. Several non-safety related loads are supplied from the safety-related load center buses and from safety-related MCCs. These non-safety loads are not automatically disconnected during postulated accidents but rather are shed manually depending on the specific accident scenario. The load centers are equipped with 600 ampere circuit-breakers with long-time and short-time, or long-time and instantaneous trip devices. The MCCs are equipped with magnetic breakers with thermal overloads or thermal/magnetic breakers. Each bus is provided with a ground detection system which consists of three ground detection voltmeters and three potential transformers. The system only provides local indication at the MCCs and does not annunciate in the control room. The control room relies on the auxiliary operator round sheet voltage recordings of the ground detection voltmeters to be informed of any ground fault on the 480 V system. The ground detector does not actuate any protective devices or indicate the location of the fault.

The team identified that since the 480 VAC electrical system at Vermont Yankee is ungrounded, an arcing/intermittent ground fault could cause excessive voltages to be impressed upon the system. Such a ground could begin on non-safety related equipment that is unprotected from the effects of a postulated high energy line break or seismic event. The installed electrical protective devices designed to provide isolation between the safety and non-safety related loads may not open during this scenario because the ungrounded system may not provide a return current path until a second ground was formed. While such a ground could possibly be detected with the installed ground detection instrumentation, there would likely be insufficient time to detect and isolate the ground before damage could occur to safety-related motors due to the possible excessive voltages. **(URI 05000271/2004008-04 - Ungrounded 480 VAC Electrical System)**

2.1.2 <u>Reactor Core Isolation Cooling (RCIC) System</u>

a. <u>Inspection Scope</u>

During the inspection, the team reviewed selected RCIC system components to ensure they would be capable of performing their required design functions for both current licensing basis conditions and the proposed EPU conditions. The team reviewed the RCIC pump and turbine, auxiliary equipment, various system valves, and instrumentation and controls. The team conducted plant equipment walkdowns, reviewed plant operating and test procedures, condition reports, test

results, maintenance history, vendor manuals, drawings, design calculations and applicable sections of the UFSAR and the TS.

b. Findings

(1) Control Valve for RCIC Lube Oil Cooler

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” because the cooling water supply to the lube oil cooler of the RCIC system was not installed as described in the RCIC system design basis. Specifically, the pressure control valve for the lube oil cooler water supply was not independent of air systems, and the piping between the pressure control valve and lube oil cooler did not contain a restricting orifice.

Description. During a review of drawing G-191174, Sheet 2, “Flow Diagram - Reactor Core Isolation Cooling,” Revision 23, the team noted that a pressure control valve, PCV-13-23, was shown as having a connection to station instrument air. The team noted that USFAR Section 4.7.5 stated that all components necessary for initiating operation of RCIC were completely independent of auxiliary ac power and station service air. The station instrument air and service air systems are interconnected and are supplied from four AC powered air compressors connected in parallel. Both the station instrument air and service air systems are classified as non-nuclear safety related. The team questioned the effect of the loss of the air supply to this valve. PCV-13-23 was installed in the 2-inch cooling water supply line to the RCIC pump lube oil cooler to regulate the flow of the cooling water supply from the RCIC pump discharge. A relief valve, SR-13-26, was installed between PCV-13-23 and the lube oil cooler for overpressure protection.

In response to the team’s questions, the licensee’s engineering personnel investigated this condition and determined that PCV-13-23 would fail in the fully open position upon a loss of air. The licensee performed a hydraulic analysis of the affected portion of the RCIC system during the inspection. The analysis determined that fully opening the pressure control valve would have resulted in a flow of approximately 170 gpm through the valve, as opposed to the design flow of 16 gpm. The analysis also determined that the lube oil cooler, which has a design pressure of 150 pounds per square inch gauge (psig), would have been exposed to a maximum pressure of approximately 1100 psig. Both relief valve SR-13-26 and relief valve SR-13-27, installed on the RCIC pump barometric condenser, would have opened to pass the expected flowrate. The licensee’s investigation determined that this condition has existed since the original operation of the RCIC system.

The licensee documented this issue in condition report CR-VTY-2004-2535 and performed an operability determination, which the team reviewed. The operability determination stated that a loss of air was considered unlikely during any of the events where the RCIC system was credited. It also concluded that, if the air supply was lost, the lube oil cooler and associated piping components would not rupture when exposed to the expected pressures. This was based, in part, on vendor testing which showed that there was significant margin above

1100 psig before these components would rupture. With regard to the potential loss of RCIC system capacity, the determination concluded that the RCIC pump would have sufficient capacity to provide the required flow to the reactor vessel even with the expected flow diversion. The licensee also initiated condition report CR-VTY-2004-2536 because the RCIC design basis document identified PCV-13-23 as a self-contained pressure control valve.

The licensee performed a limited extent-of-condition review during the inspection to verify that a similar condition did not exist for other air-operated components. No additional concerns were identified by the licensee during this review. The team also performed an independent sampled-based review and did not identify any additional issues. The licensee stated that a full extent-of-condition review would be performed as part of the resolution of CR-VTY-2004-2535. At the time of the inspection, the licensee was developing a plan to correct this design deficiency.

The team also noted that the piping between the pressure control valve and lube oil cooler did not contain a restricting orifice as described in the UFSAR. UFSAR Figure 4.7-3 indicated that a flow-restricting orifice was installed downstream of valve PCV-13-23. No such orifice exists in the system. The licensee initiated condition report CR-VTY-2004-2537 to document this concern.

Analysis. The team determined this issue was a performance deficiency since the licensee had not instituted measures to ensure that the RCIC system was installed consistent with its design and licensing basis. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the objective of ensuring the reliability of the RCIC system. The issue screened as very low safety significance in Phase I of the SDP, because it was a design deficiency that was not found to result in a loss of function. This deficiency would not have resulted in the RCIC system becoming inoperable due to a loss of air to the lube oil cooler pressure control valve.

A contributing cause of this finding is related to the cross cutting area of Problem Identification and Resolution. The licensee had previously reviewed the failure positions of air-operated equipment and issued a report, "Compressed Air Systems," dated July 16, 1989. During this review, the licensee did not identify that the pressure control valve was not independent of the instrument air system. In addition, the licensee did not fully assess all aspects of the issue associated with the pressure control valve being supplied by instrument air rather than being self contained in its initial operability determination associated with CR-VTY-2004-2535. The licensee had to complete two additional supplemental operability determinations to resolve the team's concerns.

Enforcement. 10 CFR Part 50 Appendix B, Criterion III, "Design Control," requires, in part, that design control measures be established and implemented to assure that applicable regulatory requirements and the design basis for

structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, the licensee did not implement measures to ensure that the design basis for the cooling water supply to the lube oil cooler of RCIC was correctly translated into the specifications, drawings, procedures, or instructions. Specifically, the installed pressure control valve in the lube oil cooler water supply line was not independent of air systems, and the installed piping between the pressure control valve and lube oil cooler did not contain a restricting orifice. Because this violation is of very low safety significance and has been entered into the licensee's corrective action program (CR-VTY-2004-2535), this violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000271/2004008-05 Cooling Water Supply Portion of RCIC Not Installed per Design Basis)**

(2) Failure To Correct Non-Conforming RCIC Pressure Control Valve

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," because the licensee failed to correct a longstanding non-conformance associated with PCV-13-23, the control valve that supplies cooling water to the RCIC lube oil cooler.

Description. During review of Operating Procedure (OP) 2121, "Reactor Core Isolation Cooling System," and OP 4121, "Reactor Core Isolation Cooling System Surveillance," the team identified that these procedures contained steps to manually operate PCV-13-23 during RCIC operation. The team questioned the reason for these steps, given that the RCIC system is designed to function automatically as described in UFSAR Section 4.7.4.

The team determined that during initial start-up testing, problems were identified with the automatic operation of this valve. These problems affected its ability to properly regulate the supply of cooling flow to the lube oil cooler. During the inspection, the licensee could not provide the team with an open condition report identifying this problem. Additionally, the licensee did not have an analysis to show that setting PCV-13-23 as described in the procedure would ensure an adequate flow of cooling water to the lube oil cooler. Rather, the licensee used the fact that RCIC bearing temperatures have been acceptable during surveillance testing to justify that lube oil cooling was sufficient. However, the team noted that the conditions that exist during surveillance testing may be different from those existing under design conditions (for example, use of a higher temperature suppression pool as a suction source and operation with maximum expected RCIC room temperature). These conditions would result in higher bearing temperatures when RCIC is operating under design conditions.

The team reviewed alarm response procedures for the RCIC bearing temperature alarms and determined that they were adequate to prevent damage to major RCIC components if the cooling flow was inadequate. However, the

manual operation of PCV-13-23 represents a longstanding operator work-around that creates an additional operator burden and could challenge equipment reliability if called upon to operate during an event.

Analysis. The team determined that the licensee's failure to correct a longstanding non-conformance with PCV-13-23 was a performance deficiency. Specifically, operation of this valve in a mode other than automatic may have challenged system operation if needed for an actual event. This issue was more than minor because it was associated with the Mitigating Systems attribute of Equipment Performance and affected the cornerstone objective of ensuring the reliability of the RCIC system. The issue screened as very low safety significance (Green) in Phase I of the SDP, because it was a design deficiency that was not found to result in a loss of function. While PCV-13-23 did not function automatically as designed, the licensee had implemented manual actions as a compensatory measure for the operation of this valve.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to the above, the licensee failed to correct a longstanding non-conformance associated with PCV-13-23, the control valve that supplies cooling water to the RCIC lube oil cooler. Because this issue is of very low safety significance and has been entered into the licensee's corrective action program (CR-VY-2004-2535), this issue is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy.
(NCV 05000271/2004008-06 Failure To Correct Non-Conforming RCIC Pressure Control Valve)

(3) Potential Preconditioning of RCIC MOVs

The team identified a minor finding related to Vermont Yankee's method of testing RCIC system MOVs. The team determined that a procedural requirement to conduct the quarterly RCIC system pump operability test prior to system MOV surveillance testing resulted in the operation of several RCIC system valves immediately before their required stroke-time testing. This practice could have affected the results of the stroke-time testing by preconditioning the valves and this potential impact was not evaluated by the licensee. This issue was evaluated using Inspection Manual Chapter 0612 and determined to be minor because it applied to a limited number of valves, most of the valves would not have affected system operability, a review of these valves' performance history indicated that there was significant margin to stroke-time limits, and no operability issues were noted during past testing.

2.1.3 Residual Heat Removal System (RHR)

a. Inspection Scope

During the inspection, the team reviewed selected components of the RHR system to ensure the system and components would be capable of performing their required design functions, for both current conditions and those conditions that would exist under the proposed EPU. In its power uprate submittal to the NRC, the licensee stated that it would need to take credit for the containment overpressure that would exist under postulated accident conditions in order to ensure adequate net positive suction head (NPSH) was available to the RHR pumps. The team did not assess the appropriateness of allowing credit for containment overpressure. The team did, however, perform specific reviews of the licensee's calculations to ensure that the RHR pumps would have adequate NPSH assuming such credit is given. The team's review included pressure losses associated with the RHR suction strainers, potential bubble ingestion and the potential for torus vortexing.

b. Findings

No findings of significance were identified.

2.1.4 Safety Relief Valves and Code Safety Valves

a. Inspection Scope

Due to the increased steam flow that would result from the licensee's proposed EPU, the team conducted a detailed review of General Electric (GE) Topical Report T0900, which evaluated the adequacy of the safety relief valves (SRVs) for EPU conditions. The team reviewed the GE analysis and licensee modification package associated with the installation of a third American Society of Mechanical Engineers (ASME) Code safety valve with increased relief capacity for EPU conditions. The team also reviewed the out-of-service and calibration history for the existing SRVs. Lastly, the team reviewed the back-up nitrogen bottle system, which was added to ensure an adequate supply of nitrogen to the SRVs.

b. Findings

No findings of significance were identified.

2.1.5 Reactor Feedwater and Condensate Components

a. Inspection Scope

Due to the increased feedwater flow that would be required under the licensee's proposed EPU, the team assessed the adequacy of modifications to the reactor

feedwater system. Because of the increased feedwater flow requirements, the licensee would need to run all three reactor feedwater pumps under EPU conditions, reducing the capability to mitigate feedwater transients. Included within the team's review was a recent seal replacement on a feedwater pump and modifications to the reactor feedwater pump low-suction pressure trip and reactor recirculation system runback. The team also reviewed flow control valve FCV-102-4 and its associated controls, since failure of this valve to open could disable low flow capability for the condensate pumps, resulting in a loss of feedwater flow during low-flow demands.

The team reviewed aspects of the licensee's Flow Assisted Corrosion (FAC) Program and reviewed the adequacy of the thermal sleeves located at connections between the RCIC and feedwater systems and the reactor vessel. The team conducted a walkdown of the main feedwater and condensate pumps and adjacent piping with Vermont Yankee engineering personnel. Lastly, the team inspected the feed and condensate panels in the main control room. The reviews were conducted to identify any alignment discrepancies or visible signs of deficient material conditions.

b. Findings

No findings of significance were identified.

2.1.6 Reactor Building-to-Torus Vacuum Breaker System

a. Inspection Scope

The team reviewed the components associated with the reactor building-to-torus vacuum breaker system. This system includes two redundant air-operated vacuum breaker valves, each in series with a check valve. This system functions to relieve pressure from the reactor building to the torus to protect the structural integrity of the torus. Additionally, the system must remain leak-tight from the torus to the reactor building to maintain primary containment isolation. In reviewing these components, the team assessed condition reports, operating procedures, test results, maintenance and modification history, drawings and applicable sections of the UFSAR and TS. The team's review included verification that these components would be capable of performing their required design functions for both current licensing basis conditions and the proposed EPU conditions.

The team also completed a walkdown of the reactor building-to-torus vacuum breakers and their air-operators, check valves and associated piping. Additionally, the team reviewed operator burden and work-around lists to identify any deficiencies that could affect operation of these components.

b. Findings

No findings of significance were identified.

2.1.7 Review of Transient Analysis Inputs

a. Inspection Scope

During the inspection, the team reviewed selected plant parameters used by the licensee as inputs into its transient analyses. Included in this review were analyses performed solely to support the proposed EPU. In conjunction with this review, the team conducted plant equipment walkdowns, reviewed plant procedures and calculations, and discussed calculations and parameters with plant design engineers.

b. Findings

Introduction. The team identified a finding of very low safety significance involving a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because the licensee had neither established the correct condensate storage tank (CST) temperature limit for use in the plant transient analyses nor translated this CST temperature into plant procedures.

Description. During the inspection, the team noted that although the CST temperature was monitored on operator logs, the licensee had not established a maximum temperature limit for the CST. A CST temperature limit of 90 degrees Fahrenheit (EF) was used as an input to several plant transient analyses, including Transient Analysis VYC-1825, "Analysis of Suppression Pool Temperature for Relief Valve Discharge Transients," Revision 0. The CST temperature used for this analysis was based on the maximum ambient summer temperature of approximately 90EF and did not take into account the recirculated hotwell water that has on occasion raised the CST temperature to approximately 120EF.

In addition, the team noted that in December 2002, the licensee had also identified that there was no maximum CST temperature limit and that CST temperature had previously exceeded the temperature assumed in the high pressure coolant injection (HPCI) and RCIC design basis documents for calculating pump NPSH. The licensee documented this condition in CR-VTY-2002-2942. At that time, the licensee performed a limited evaluation and determined that the non-conservative CST temperature had little to no effect on the transient analyses. The team reviewed this evaluation and determined that transient analysis VYC-1825, which assessed the adequacy of the NPSH of the pumps supplied from the CST or the suppression pool, would be affected by the increased CST temperature.

In response to the team’s concerns, the licensee reviewed the transient analyses and identified that the relief valve discharge transient was the most limiting. The licensee determined that using the higher CST temperature of 120EF led to an increase in suppression pool temperature, which reduced the net positive suction head margin for the most limiting component, the core spray pumps, from 0.5 feet to 0.0 feet. The team reviewed the input parameters to the NPSH calculation for the core spray pumps and determined that because of conservatism in other aspects of the calculation, the core spray pumps would still have adequate NPSH to remain operable.

The team determined that in the licensee’s EPU submittal to the NRC, the licensee had not taken into account the higher CST temperature for all transient scenarios. As a result of this issue, the licensee began an extent-of-condition review of all calculations, drawings, and inputs to transient analyses where a non-conservative maximum CST temperature was used, both for current plant conditions (CR-VTY-2004-2600) and for analyses associated with the planned EPU (CR-VTY-2004-2799). The licensee also instituted a tentative maximum temperature limit of 120EF for the CST.

Analysis. The team determined this issue was a performance deficiency since the licensee had not used the correct CST temperature in the plant transient analysis and had not translated the CST temperature limit into the station procedures. Specifically, using the correct CST temperature in the relief valve discharge transient analysis resulted in a higher suppression pool temperature and lowered the available net positive suction head to the core spray pumps. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the reliability of the core spray system. The issue screened as very low safety significance (Green) in Phase I of the SDP, because it was a design deficiency that was not found to result in a loss of function. Although available NPSH margin was lowered, adequate NPSH for the core spray pumps remained due to the conservatism that existed in other aspects of the licensee’s NPSH analysis.

A contributing cause of this finding is also related to the cross-cutting area of Problem Identification and Resolution. The licensee identified this issue in December 2002, but concluded that the non-conservative CST temperature had little to no effect on the transient analyses.

Enforcement. 10 CFR Part 50 Appendix B, Criterion III, “Design Control,” requires, in part, that design control measures be established and implemented to assure that applicable regulatory requirements and the design basis for structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, the licensee had neither established the correct condensate storage tank (CST) temperature limit for use in the plant transient analyses nor translated the CST temperature limit into plant procedures. Because this finding is of very low safety significance and

has been entered into the licensee's corrective action program (CR-VTY-2004-2600, CR-VTY-2004-2793, and CR-VTY-2004-2799), this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000271/2004008-07 Failure to Implement Adequate Design Control for Condensate Storage Tank Temperature)**

2.2 Review of Operator Actions

a. Inspection Scope

During the inspection, the team reviewed risk-significant, time-critical operator actions that had little margin between the time required and time available to complete the action. The team determined the review scope and performed the detailed review of critical operator actions using risk information contained in the licensee's PRA, Operator Task Validation Studies, Emergency Operating Procedures (EOPs), Power Uprate Safety Analysis Report (PUSAR), Appendix R Analyses, Off-Normal and Operating Procedures, and the licensee's CR database. The team performed a detailed review of the following time-critical and low-margin operator actions:

- Monitoring of the Vernon tie line to ensure availability as a station blackout source.
- Manual initiation of the RCIC system using alternate shutdown panels.
- Initiation of the standby liquid control (SLC) system with the main condenser failed.
- Manual initiation or control of feedwater and condensate flow under normal and transient conditions, in single element or three element control.
- Manual initiation of RCIC system from the control room.

For all the above operator action scenarios, the team verified that operating procedures were consistent with operator actions for a given event or accident condition and that the operators had been adequately trained and evaluated for each action. The team also reviewed the fidelity between EOPs, pump NPSH calculations and containment spray operation to ensure proper EOP implementation. Control room instrumentation and alarms were also reviewed by the team to verify their functionality and to verify alarm response procedures were accurate to reflect the current plant configuration. Additionally, the team performed a walkdown of accessible field portions of the reviewed systems to assess material condition and to verify that field actions could be performed by the operators as described in plant procedures.

The team also reviewed each operator action to assess the impact the proposed EPU could have on further reducing the margin available for task completion and to verify that the associated EPU plant modifications would be reviewed by the licensee for their effect on the operators' ability to complete the critical actions within the required time parameters.

b. Findings

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because the licensee did not adequately coordinate between the operations department and the engineering organization procedure revisions that increased the length of time required to place the reactor core isolation cooling system in service from the alternate shutdown panels. As a consequence, the licensee did not revise its Vermont Yankee Safe Shutdown Capability Analysis (SSCA).

Description. The Vermont Yankee SSCA relies on the reactor core isolation cooling (RCIC) system to be placed in service from the alternate shutdown panels prior to reactor water level reaching the top of active fuel following a loss of feedwater flow. In December 1999, the Vermont Yankee SSCA documented that, for the present day 100 percent power level, it would take 25.3 minutes for reactor water level to reach the top of active fuel following a loss of feedwater and that it would take approximately 15 minutes to place the RCIC system in service from the alternate shutdown panels. The Vermont Yankee SSCA concluded adequate margin (approximately 10 minutes) existed to ensure that the RCIC is placed in service prior to reactor water level reaching the top of active fuel.

In June 2001 the Operations Department conducted an additional review of the time it would take to place RCIC in service from the alternate shutdown panels. The Operations Department determined that, using the version of the procedure in effect in June 2001, it would take 19.3 minutes to place RCIC in service from the alternate shutdown panels .

During the inspection, using the version of the procedure in effect during the inspection period, the team performed a field walkdown with licensed operators to validate that RCIC could be placed into service from the alternate shutdown panels within 19.3 minutes. The team noted that since June 2001, the licensee had added steps in the procedure to comply with Electrical Safety Standards. Based on the team's validation, the total time to place RCIC in service from the alternate shutdown panels was determined to be approximately 21 minutes. The team concluded that this time was still within the 25.3 minute limit stated in the Vermont Yankee SSCA.

Additionally, the team found that the licensee had not revised the December 1999 Vermont Yankee SSCA to reflect the June 2001 time estimate or present day version of the procedure to place RCIC in service from the alternate

shutdown panels. The team also determined that the licensee's engineering organization was unaware that the time to complete the task had increased from approximately 15 to 21 minutes and had effectively reduced the time margin available for event mitigation from about 10 minutes to 4 minutes at the current full power level. As a consequence, the engineering organization had not revised the Vermont Yankee SSCA.

The team reviewed the impact the licensee's proposed EPU would have on this issue. Based on an EPU power level, the licensee calculated it would take 21.3 minutes for reactor water level to reach the top of active fuel following a loss of feedwater. Therefore, the team concluded that for the proposed EPU, the ability to place the RCIC in service from the alternate shutdown panels (21 minutes) prior to reactor water level reaching the top of active fuel (21.3 minutes) is questionable. Additionally, the team found that the December 1999 value of the time to place RCIC in service from the alternate shutdown panel was used in licensee Technical Evaluation (TE) 2003-065, "Appendix R PUSAR Input." The TE was then used as an input to the Vermont Yankee Power Uprate Safety Analysis Report (PUSAR) and submitted to the NRC as part of the power uprate application. The licensee initiated CR-VTY-2004-2552 and 2004-2614 in response to these issues.

Analysis. The team considered this finding to be a performance deficiency since the licensee did not coordinate between the operations department and engineering department regarding procedure revisions which increased the time required to place the RCIC in service from the alternate shutdown panels. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Human Performance and affected the cornerstone objective of ensuring the availability of the RCIC system. Furthermore, this finding resulted in the use of the December 1999 value of time to place RCIC in service from the alternate shutdown panel in documents submitted to the NRC as part of the Vermont Yankee PUSAR. The issue screened as very low safety significance (Green) in Phase I of the SDP because it was a design deficiency that was not found to result in a loss of function. At the present 100 percent power level, RCIC could be placed in service from the alternate shutdown panels prior to reactor level reaching the top of active fuel.

Enforcement. 10 Part CFR 50, Appendix B, Criterion III, "Design Control," requires, in part, that revision of documents shall be coordinated among participating organizations. Contrary to above, between June 2001 to September 2004, the licensee did not adequately coordinate between the operations department and the engineering organization regarding procedure revisions that increased the length of time required to place the reactor core isolation cooling system in service from the alternate shutdown panels. Because this finding is of very low safety significance and has been entered into the licensee's corrective action program, it is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy. **(NCV**

05000271/2004008-08 Failure to Coordinate Information Related to Safe Shutdown Capability Analysis Report)

2.3 Review of Operating Experience and Generic Issues

a. Inspection Scope

During the inspection, the team reviewed selected operating experience issues that had been identified at other facilities for their possible applicability to Vermont Yankee. Several issues that appeared to be applicable to Vermont Yankee were selected for a more in-depth review. Additional consideration was given to those issues that might be impacted by the licensee's planned EPU. The issues that received a detailed review by the team included:

- An NRC inspection finding at the Point Beach Nuclear Power Station, documented in IR 50-266/2004-004, concerning the use of a non-conservative CST temperature in accident and transient analyses.

- Licensee Event Report (LER) 2003-003-00, issued on September 29, 2003, from the Byron Station where the licensee had exceeded its licensed maximum power level due to inaccuracies in feedwater ultrasonic flow measurements caused by signal noise contamination.

- An NRC inspection finding from the Peach Bottom Station, documented in IR 50-277/2002-011, concerning inadequate Emergency Operating Procedures to return the suction of the High Pressure Coolant Injection (HPCI) system from the suppression pool to the CST in order to ensure self-cooled HPCI lube oil temperatures remained within analyzed limits.

- Information Notice 2001-13, "Inadequate Standby Liquid Control Relief Valve Margin," issued on August 10, 2001, concerning a problem identified at the Susquehanna Station involving inadequate SLC system relief valve margin after a power uprate increased the relief valve setpoint pressure, thereby increasing SLC discharge pressure. This was complicated by using a non-conservative maximum reactor vessel pressure in accident analysis.

- NRC Generic Letter (GL) 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Power-Operated Valves," pertaining to the periodic testing of motor-operated valves. With regard to this GL, the team reviewed the NRC safety evaluation report that documented the NRC staff's understanding of the licensee's commitments and plans for establishing a periodic verification program. The team also reviewed procedures, test and maintenance records, corrective action documents, and correspondence relative to four RCIC system MOVs.

Enclosure

b.1 Findings

Introduction. The team identified a Green non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, “Test Control,” because the licensee conducted periodic testing of MOVs using test instrumentation that had not been validated to be adequate for its intended function. Additionally, the test procedures did not incorporate requirements and acceptance limits contained in applicable design documents.

Description. In its SER dated December 14, 2000, the NRC provided its basis for accepting Vermont Yankee’s response to NRC GL 96-05, “Periodic Verification of Design-Basis Capability of Safety-Related Power-Operated Valves.” The SER documented the licensee’s intentions to use motor current data acquired from the MCCs as a way of detecting actuator and valve degradation. The SER also documented Vermont Yankee’s intention to verify this testing methodology by comparing the data with direct torque and thrust measurements at the valve over extended intervals. In addition, the SER stated the licensee would have to determine MCC test instrumentation accuracies and sensitivities to MOV degradation, as well as evaluate changes in MCC data and MOV thrust and torque performance.

During the inspection, the team concluded that Vermont Yankee had not validated the adequacy of the MCC diagnostic test instrumentation with respect to its ability to provide detect actuator torque and stem thrust degradation that would indicate actuator or valve degradation. A cooperative effort with Crane-MOVATS to perform the required validation was terminated in March 2004, when the parties determined that a statistically meaningful and valid correlation of MCC to direct diagnostic test data that would allow setting switches could not be completed. As a result of the team’s concerns, the licensee entered this issue into the corrective action program on CR-VTY-2004-2802.

The team also identified that separate procedures (OP 5217 and OP 5287) had been established to obtain and evaluate MCC diagnostic test data; however, neither of these procedures included specific acceptance criteria tied to stem thrust or available design margin. The SER stated that an acceptance procedure for MCC testing was under development to specify parameters to be monitored for trending, including specific acceptance criteria. The team observed that the lack of acceptance criteria could lead to the inconsistent evaluation of the data between different reviewers. Also, the documentation of problem identification and resolution of issues identified through test data review was missing or unclear. An inspector-identified example of entering improper test data into the MOV test package was entered into the corrective action program on CR-VTY-2004-2623.

The team also identified that no administrative or procedural prohibition had been implemented against using MCC testing to set MOV switches, and that the procedures specifically allowed establishing a baseline with MCC testing

(OP 5287). The MOV program had been revised in 2002 to eliminate any periodicity requirements for “at-the-valve” diagnostic testing that can measure torque and thrust to known accuracies. The team identified and the licensee confirmed that the MCC test equipment had been used in at least one instance to set MOV switches on one of the four RCIC valves reviewed. Also, the team identified several cases where diagnostic testing following replacement of the valve packing was limited to MCC testing. The team noted that packing replacement affects stem friction and consequently changes in stem thrust. Since the MCC testing instrumentation had not been validated, the team concluded that the change in stem friction from initial set-up was indeterminate for these valves.

Analysis. The performance deficiency was the failure to validate motor-operated valve test instrumentation to ensure its adequacy and to establish test procedures with adequate acceptance criteria tied to stem thrust or available design margin. Specifically, there was no analysis demonstrating that testing conducted at the MCC ensured the development of proper operating thrust at the valve to ensure the MOV would perform satisfactorily under design basis conditions. This issue was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems and components that respond to initiating events. Specifically, the unvalidated test method had the potential to affect the reliability of safety-related motor-operated valves. The issue screened as very low safety significance (Green) in Phase I of the SDP, because it was a qualification deficiency that was not found to result in a loss of function. The team did not identify any examples of degraded or inoperable valves during the inspection and noted that the design basis calculations for the MOVs reviewed had available thrust margin of greater than 60 percent.

The inspectors also identified that a contributing cause of the finding was related to the human performance cross-cutting area, in that, the licensee did not manage NRC commitments and conditions documented in the SER for the GL 96-05 MOV periodic verification program.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XI, “Test Control,” requires that a test program be established to ensure that all testing required to demonstrate that systems and components will perform satisfactorily in service is performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. The test procedures shall include provisions for ensuring that adequate test instrumentation is available and used. Contrary to the above, Vermont Yankee had conducted MOV diagnostic tests using procedures that did not include acceptance limits which were correlated to and based on applicable (stem thrust and torque) design documents. Additionally, MOV diagnostic testing had been conducted solely from the motor control centers using test instrumentation that had not been validated to ensure its adequacy. Because this finding is of very

low safety significance and has been into Vermont Yankee's corrective action program (CR-VTY-2004-2802 and CR-VTY-2004-2644), it is being treated as a non-cited violation, consistent with Section VI.A of the NRC's Enforcement Policy. **(NCV 05000271/2004008-09 Failure To Establish Adequate MOV Periodic Test Program)**

b.2 Observations

The team also had other observations regarding the licensee's NOV program. The team concluded these observations did not impact valve operability due to existing value capability margins.

The team identified that Vermont Yankee had not maintained current the risk ranking of MOVs. At the time that the SER was issued, the licensee's risk ranking of the MOVs was considered acceptable. During a review of program documents during this inspection, the team noted that low- and medium-risk MOVs were specified for test at every other refueling outage, whereas, high-risk MOVs were specified for testing every refueling outage. For the RCIC system MOVs reviewed, the team noted that several valves had the same risk achievement worth (RAW), but they were assigned different risk rankings in the MOV program documents and consequently were not tested at the same periodicity. Discussions with Vermont Yankee's risk analyst indicated that the licensee's PRA had been updated in 2000 and May 2004; however, the updated PRA data were not reflected back into the MOV risk ranking. This issue was entered into the corrective action program on CR-VTY-2004-2798.

The team also concluded that Vermont Yankee's trending methods to identify degradation from design basis conditions were informal. The SER documented the existence of established procedures to review and trend MOV failure and diagnostic test data every two years. Primary MOV parameters identified for trending were various thrust values, stem friction coefficient, load sensitive behavior and dynamic margin. The SER noted that Vermont Yankee would perform quantitative and qualitative assessments looking for overall changes in MOV performance, including the use of diagnostic trace overlays and analysis. The team found that the procedure referenced in the SER (DP 0210) had been canceled. The trending of alternating current MOVs was moved to the procedure for evaluating MCC test data; however, a procedure for trending direct current MOVs had not been established. Currently, Vermont Yankee's trending program consists of reviewing the data from a diagnostic test to the results of the previous test, which may not identify degradation from the established baseline or identify slow but continual degradation. This issue was entered into the corrective action program on CR-VTY-2004-2644.

4OA6 Meetings, Including Exit

The team presented the issues identified during the inspection to Mr. Dreyfuss and other members of the licensee's staff at a team debrief on September 3, 2004.

On October 27, 2004, the inspection team leader provided the preliminary results of the inspection, including risk significance and enforcement, to Mr. Bronson, Mr. Dreyfuss, and other members of licensee's staff in a teleconference call.

The preliminary results of the inspection were also included in a letter to Vermont Yankee Nuclear Power Station dated November 5, 2004, which was originally issued in preparation for a planned public exit meeting.

A final closeout discussion on the inspection was held with Mr. Thayer, Mr. Bronson and other members of the licensee's staff via teleconference on November 23, 2004. The Vermont State Nuclear Engineer was invited to the closeout discussion, but was not available to attend.

ATTACHMENT A

Summary of Items Reviewed

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
115 kV - Breaker K1	Transformer T-4 feed to 115 kV bus: required to supply power from the 345 kV switchyard to the Startup Transformers.	No automatic actions required except fault clearing; safety busses would disconnect or be prevented from connecting to circuit after a fault.
115 kV - K.1 Logic Relay	RCIC logic relay K.1 fails to operate on demand. Rationale: Malfunction of RCIC turbine trip instrumentation could cause loss of RCIC System.	The inspectors found no specific operator action for this component and that a failure of the logic relay would result in control room alarms which would be responded to by the operators. The inspectors found that related control room alarms were functioning properly, and that the associated alarm response procedures were current.
125 V Battery B-1 and A-1	Station Battery: Supplies power to the station 125 VDC loads when the battery chargers are not available.	Detailed review completed.
24 Vdc - ES-24DC-2	Power Supply Converter: Supplies power to the 24 VDC ECCS Analog Trip System.	No low margin or other issues identified.
345 kV - Breaker 381-1	Northfield 345 kV line to 345 kV North Bus: required to provide power from the Northfield 381 to the 345 kV switchyard.	Detailed review completed.
4 Kv - Breaker 12	Bus 1 Feed Breaker from UAT: required to open on generator trip to enable access of one safety train to the offsite source through the SUT	No low margin issues identified.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
4 Kv - Breaker 13	Bus 1 Feed Breaker from SUT: required to close on generator trip to enable access of one safety train to the offsite source through the SUT .	Detailed review completed.
4 Kv - Breaker 22	Bus 2 Feed Breaker from UAT: required to open on generator trip to enable access of one safety train to the offsite source through the SUT.	The inspectors found that the only operator action for this component was breaker open/close operation. Additionally, the inspectors found that the related control room alarms were functioning properly and that the associated alarm response procedures were current. The inspectors found no issues with this component related to operator actions.
4 Kv - Breaker 23	Bus 2 Feed Breaker from SUT: required to close on generator trip to enable access of one safety train to the offsite source through the SUT.	Detailed review completed.
4 Kv - Breaker 3V	Vernon Supply Breaker to Bus 3: required to supply power from the Alternate AC Power source to one 4160V safety bus.	No specific issues identified with breaker. Other issues reviewed as part of overall Station Blackout Capability.
4 Kv - Breaker 3V4	Vernon Tie Breaker: required to supply power from the Alternate AC Power source to either 4160V safety bus.	Detailed review completed.
4 kV UV Relays	4160V Undervoltage Relays: required to provide adequate voltage to safety-related AC loads, reset setpoint must be optimized to prevent spurious loss of offsite power.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
69 kV - Vernon Generator	Vernon Hydroelectric generator station: required to supply power from the Alternate AC Power source to either 4160V safety bus.	Detailed review completed.
69 kV to 4160 V Vernon Transformer	Vernon Tie Transformer: required to supply power from the Alternate AC Power source to either 4160V safety bus.	Detailed review completed.
125 VDC Distribution Panels	Supplies 125 VDC loads.	Detailed review completed.
Alignment of RHRSW to the RPV	Operator fails to align the RHRSW injection to RPV.	Aligning RHRSW injection to the RPV is one of the methods which can be used for RPV injection to prevent core damage in accordance with EOPs given an ATWS scenario. The validated time through simulator observation was 1 minute to complete the actions for alignment. Additionally, prior to using RHR SW for RPV injection, other systems such as condensate/feedwater , CRD, and RHR will be used to attempt to fill the RPV. The operators are regularly trained and evaluated in this event scenario further reducing the likelihood of the task not being completed within the required time.
Bus Transfer Scheme	Circuit breakers, synchronism check relays, timing relays, and voltage relays required to enable transfer of 4160V buses from the Unit Aux Transformer to the Startup Transformers.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Closure of Vernon Tie Breakers	Operator fails to close the Vernon tie breakers.	One of the primary AC power recovery actions in the event of a loss of normal power is to use the dedicated tie line from the Vernon hydro Station to power either 4260VAC Bus 3 or 4 (vital power). The action is performed by the operators in the main control room by manipulating switches for 2 DC powered breakers. Validation studies and operator observation in the simulator have shown that the task can be accomplished in less than 4 minutes. Adequate margin exists currently and for the CPPU to accomplish the action. Additionally, operator response to loss of power events is trained regularly in the simulator and classroom. While no issues identified with VY operator actions, a finding was identified with the licensee's overall station blackout response.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Condensate Pump	Review condensate operation before and after the power uprate (including recirc pump runback modification). The Condensate and Feedwater system does not directly perform any safety-related function. Portions of the Feedwater system and check valves provide Reactor Coolant Pressure Boundary and Containment Isolation functions. The condensate pumps 1) supply water to the Feedwater pumps and 2) provide sufficient NPSH for operation of the FW pumps. The loss of a condensate pump could be a contributing factor to a transient initiation. The condensate pumps are directly impacted by the EPU due to the need to increase the flow volume by approximately 20%.	No low margin or other issues identified.
Containment Pressure	During a loss of coolant event or an ATWS the containment pressure will be elevated and the suppression pool level will increase.	Detailed review completed.
CST Transient Analysis Temperature Non-conservative	Transient analysis Condensate Storage Tank Temperature non-conservative compared to actual maximum operating temperatures. This issue stems from a similar event at Point Beach.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
CST Level Instrumentation	Rationale: Important for maintaining required CST inventory for RCICS and controlling automatic transfer of RCICS suction to the suppression pool.	Detailed review completed.
CV-109	Failure of check valve CV-109 (valve between the N2 bottle and the SRV) to open. Failure of this check valve to open will prevent N2 supply to the Main Steam Safety Relief Valves.	Detailed review completed.
CV-19	RCIC check valve CV-19 (RCIC suction check valve from the CST) fails to open on demand. This valve must open to provide flow from CST to RCIC pump suction, and close to prevent flow from torus to CST during RCIC pump suction transfer.	A detailed review was not performed for this check valve because no performance problems were indicated from the maintenance history.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
CV-2-1A, 1B, 1C	RFP discharge check valves. They are risk significant because if they fail to close following an RFP trip they could make other RFPs inoperable. Prior to EPU two pumps are operational. After EPU three pumps will be operational. When two pumps are operational, one of the MOVs, 4A, 4B or 4C will be closed for the non-operational pump as such, this is not a current potential event. However, after EPU the third valve will not be closed thus this is a potential failure scenario.	A detailed review was not performed for these check valves because no performance problems were indicated from the maintenance history.
CV-22	RCIC check valve CV-22 (RCIC injection path discharge check valve) fails to open on demand. This valve must open for RCIC injection flow. The valve must also fully close when the pump is not in operation to prevent back-leakage and a possible waterhammer.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
CV-2-27B	This valve is the feedwater isolation valve upstream of the RCIC injection path. The risk significant function of the component is to close to prevent RCIC from flowing back into the feedwater system. EPU uprate will increase the flow through this check valve by approximately 20%, however the function of the valve is not altered.	A detailed review was not performed for this check valve because no performance problems were indicated from the maintenance history.
CV-2-28B	Feedwater check valve CV-28B ('B' feedwater line check valve inside containment) fails to open on demand. This valve is located on drawing G-191167, H-5. Failure to open will prevent flow from either the RCIC or the Feedwater system. EPU uprate will increase the flow through this check valve by approximately 20%, however the function of the valve is not altered.	A detailed review was not performed for this check valve because no performance problems were indicated from the maintenance history.
CV-2-96A	Feedwater check valve V96A fails to open on demand. Failure of this valve will prevent flow from either the RCIC or the FW system. EPU uprate will increase the flow through this check valve by approximately 20%, however the function of the valve is not altered.	A detailed review was not performed for this check valve because no performance problems were indicated from the maintenance history.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
CV-40	RCIC check valve CV-40 (RCIC suction check valve from the suppression pool) fails to open on demand. This valve must open to provide a flow path from the torus to the RCIC pump suction.	A detailed review was not performed for this check valve because no performance problems were indicated from the maintenance history or walkdown.
CV-6/7	RCIC check valves CV- 6/7 (RCIC turbine exhaust check valves to torus) fails to open on demand.	Detailed review completed.
CV-72-109	Failure of check valve CV-109 (N2 bottle supply check valve to the plant N2 system) to close. The component is risk significant because if the check valve failed to close, the N2 bottle could bleed down to the plant N2 system.	Detailed review completed.
Digital Feedwater Control/Single Element Control	Following the modification that installed the digital feedwater control system, the licensee had problems with loss of inputs to the three-element controller (steam flow). This resulted in a reactor level transient. Since the event the plant had been operating in single-element control. Evaluate the modification and the acceptability of operating in single-element. Also determine if operation in single-element control would challenge the licensee's assumption that the plant would not scram following a single reactor feed pump trip, post-uprate.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
DPIS-83/84	Spurious high steam flow signal. This steam flow instrument isolates RCIC steam in the event of a line rupture (indicated by high flow). Spurious isolation would result in the loss of RCIC flow.	These instruments are not included because there is significant margin in the setpoint to detect a steam line rupture, as well as margin between the normal operating point and the setpoint.
EOP/NPSH Fidelity	Verify fidelity between Emergency Operation Procedures and NPSH calculations and Containment Spray operation.	Detailed review completed.
FCV-2-4	FCV.4 (condensate pump minimum flow valve) fails to open on demand.	Detailed review completed.
FCV-2-4 Instrumentation	Failure of FCV.4 (condensate pump minimum flow valve) control instrumentation.	Detailed review completed.
Feed/Condensate Control	Operator fails to initiate and/or control feedwater/condensate.	Detailed review completed.
FT-58/FE-56	RCIC pump discharge flow instrument. This instrument is associated with the RCIC turbine control logic.	Detailed review completed.
GE SIL 351	GE SIL 351 - HPCI and RCIC Turbine Control System Calibration.	Vermont Yankee implemented SIL 351R.2 and provided the procedural changes recommended in the SIL for the HPCI system (OP 5337 Rev. 7). SIL 351 does not apply to RCIC since RCIC does not use a ramp generator (RGSC). This SIL is primarily procedural change recommendations and is not a high risk/low margin system.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
GE SIL 377	GE SIL 377 RCIC Startup Transient Improvement with Steam Bypass (June 24, 1982).	GE SIL 377 recommended a bypass for the steam supply line to the turbine for improved startup performance during a transient where RCIC is needed. This does not apply to Vermont Yankee since the SIL was a recommendation for plants who have issues with cold startup of the RCIC system. Upon talking to the system engineer, these issues have not existed for at least 20 years at VY.
GE SIL 467 (Bistable Vortexing)	GE SIL 467 and IEN 86-110 - Bistable vortexing is still a phenomenon that occurs periodically at VY.	The first occurrence of bistable vortexing at Vermont Yankee was following beginning of cycle 12 when recirculation system piping was replaced; however, this is a low risk event and thus does not meet the high risk / low margin criteria for this inspection. Vermont Yankee has had problems with bistable vortexing in the past and responded in depth to this SIL. The licensee responded to the SIL, added discussion on bistable vortexing at VY and action items for operators when bistable vortexing occurs. A review of Vermont Yankee's response to SIL 467, showed VY satisfied GE's recommended actions and placed guidance in OP 2110, Recirculation Procedure to aid the operators in identifying bistable vortexing.
GL 96-05, MOV Periodic Verification	GL 96-05 - Implementation of program for MOV Periodic Verification (As applicable to the selected sample of valves RCIC-MOV-15, 16, 131 and 132)	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
IN 2001-13 (SLC Relief Valve Margin)	Information Notice 2001-13 (8/10/01) - Inadequate Standby Liquid Control System Relief Valve Margin (Susquehanna, Units 1 and 2) Susquehanna's power uprate increased SRV setpoint pressure thus increasing SLC discharge pressure. However, the maximum SLC pump discharge pressure used a non-conservative maximum reactor vessel pressure in accident analysis.	Detailed review completed.
LER 3871995009 (LCO 3.0.3 Entry)	LER 1995-009-00 (7/3/95) - Condition Prohibited by the Plant's Technical Specifications (Susquehanna, Unit 1) - Non-conservative plant input into reactor core flow calculation.	Feedflow used in the analysis for power uprate is consistent with current feedflow indications.
LER 3251997005 (FW Indication Error)	LER 1997-005-01 (8/8/97) - Feedwater Flow Indication Discrepancy (Brunswick Steam Electric Plant, Unit 1).	Vermont Yankee does not have and is not required to have chemical tracer mass flow rate tests. This is more conservative then having the tracers since the chemical tracer mass flow rate tests are controversial and have had past issues. VY is waiting for industry or regulatory guidance on this issue before adding this test.
LER 2961998001 (LOCA Sensor Problem)	LER 1998-001-00 (4/1/1998) - Computer Modeling Indicates Sensors May Not Detect All Possible Break Locations (Browns Ferry, Unit 3).	Vermont Yankee does use the GOTHIC computer code to analyze high energy pipe breaks; however, this is a low risk issue and presented no significant safety issue at Browns Ferry.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
LER 2601999009 (Scram Due to EHC Leak)	LER 1999-009-00 (10/14/99) - Manual Reactor Scram Due to EHC Leak (Browns Ferry Nuclear Power Station, Unit 2).	The EHC leak was on a very specific 3/8 inch nominal outer diameter tubing connection which consisted of socket weld glands and standard nuts to connect the accumulator to a pressure transmitter. The leak was due to poor fabrication and poor work practices specific to Browns Ferry.
LER 2372001005 (1/7/02)	LER 2001-005-00 (1/7/02) - Unit 2 Scram Due to Increased First Stage Turbine Pressure (Dresden, Unit 2).	Vermont Yankee responded to GE SIL 423, in 1998, by implementing corrective actions.
LER 4612002002 (Inadequate PM on FW System)	LER 2002-002-00 (7/11/02) - Inadequate Preventive Maintenance Program for the Feedwater System Results in Lockup of a Turbine-Driven Reactor Feed Pump and Scram on High Reactor Pressure Vessel Water Level During Extended Power Uprate Testing (Clinton Power Station). Feedwater increased due to the power uprate; however, the feedwater limit switch did not increase to accommodate this increase in flow.	This operating experience does not apply since Vermont Yankee does not have turbine driven feedwater pumps, and this issue does not apply to other turbine driven pumps in the plant.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
LER 3412002005 (Non-Conservative Setpoint)	LER 2002-05 (1/16/03) - Discovery of Non-Conservative Setpoint for the Thermal-Hydraulic Stability Option III Oscillation Power Range Monitor (OPRM) Period Based Algorithm, Tmin (Fermi, Unit 2).	This OE does not apply to Vermont Yankee since power oscillations are monitored using approved BWROG Option 1D not Option III. Vermont Yankee does not have Oscillation Power Range Monitors, Period Based Detection Algorithms, and Tmin values. Option III is used for larger BWRs that have local power oscillations. Since Vermont Yankee has a small BWR core, only core-wide oscillations occur (not local oscillations). The inspector met with an individual from power uprate (and used to work in reactor engineering) and discussed, in detail, core monitoring using Option 1D for the new ARTS/MELLA core design and the power uprate core design.
LER 4542003003 (Maximum Power Exceeded)	LER 2003-003-00 (9/29/03) - Licensed Maximum Power Level Exceeded Due to Inaccuracies in Feedwater Ultrasonic Flow Measurements Caused by Signal Noise Contamination (Byron).	Detailed review completed.
LER 3411992009	LER-92-009-00 (11/20/92) - Safety Relief Valves Set Pressure Outside Technical Specifications (Fermi, Unit 2).	VY has had no issues with setpoint drift on the SRVs or RVs in containment. Setpoint drift considered in this LER was an indication of disc-to-seat sticking due to corrosion binding on the SRVs and RVs at Fermi thus making these valves fail their set pressures tests.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
LSHH-4A	Level switch LSHH 4A contacts fail/short. High Water Make up - Condenser level Control Switch Fails high - auto make malfunctions to the CST - Operator Action is required. No EPU impact.	Operator can take manual action to overcome this failure. The consequence of the failure of the switch is not significant because the operator can take manual control.
Manual Initiation of HPCI/RCIC	Operator fails to manually initiate HPCI and RCIC systems.	Detailed review completed.
Manual Operation of SRVs (Medium LOCA)	Operator fails to manually open the SRVs for a medium LOCA.	Emergency Operating Procedures (EOP) require operator action to manually open the SRVs to depressurize the reactor under medium break LOCA conditions. Validation studies and operator observations in the simulator have shown that given various factors that influence human performance (stress, training, equipment failures, etc.), the task to open the SRVs manually would be accomplished in less than 7 minutes which is lower than the 33 minutes (or 24 minutes for CPPU) needed to assure > 1/3 core coverage. Additionally, operator training frequently focuses on this event making it unlikely that the operator would fail to perform the task within the required time.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Manual Operation of SRVs (Small LOCA/Transient)	Operator fails to manually open the SRVs for transient/small LOCA.	Emergency Operating Procedures (EOP) require operator action to manually open the SRVs to depressurize the reactor under transient and small break LOCA conditions. Validation studies and operator observations in the simulator have shown that given various factors that influence human performance (stress, training, equipment failures, etc.), the task to open the SRVs manually would be accomplished in less than 5 minutes which is much lower than the 66 minutes (or 48 minutes for CPPU) needed to assure > 1/3 core coverage. Additionally, operator training frequently focuses on this event making it unlikely that the operator would fail to perform the task within the required time.
Manual RCIC operation-Appendix R Safe Shutdown	Appendix R Safe Shutdown Analysis - Operator fails to manually initiate RCIC system using alternate shutdown panels (Generic Human Actions that are Risk Important), and GE document NEDC-330090P, Table 10-5 (Assessment of Key Operator Action).	Detailed review completed.
MOV-131	RCIC MOV 131 (RCIC turbine steam supply valve) fails to open on demand. This valve is required to open to provide steam to the RCIC turbine for operation.	Not included because valve has adequate design margin to open when required.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
MOV-132	RCIC MOV 132 (cooling water valve to the RCIC lube oil cooler) fails to open on demand. This valve is required to open to provide cooling water to the RCIC pump lube oil cooler. Failure to cool the lube oil could result in failure of the pump/turbine.	Not included because valve has adequate design margin to open when required.
MOV-15/16	RCIC MOV 15/16 (steam supply to RCIC turbine) fails closed during its mission time. These valves are required to close in the event of a line break in the RCIC turbine steam supply to isolate the HELB. These valves are also required to remain open when the RCIC pump is required to operate.	Detailed review completed.
MOV-18	RCIC MOV 18 (RCIC pump suction valve from the CST) transfers closed during its mission time. This valve is required to automatically close when the RCIC pump suction is transferred from the CST to the torus. This valve must remain open while the RCIC pump is operating from the CST.	Not included because valve has adequate design margin to close when required.
MOV-21/20	RCIC MOV 21 (inboard discharge valve to the reactor vessel) fails to open on demand. Also look at MOV-20 (the normally open outboard discharge isolation valve). These valves must automatically open to provide RCIC injection flow in response to an RCIC initiation signal.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
MOV-27	This is the RCIC minimum flow valve. This valve is required to open at low RCIC flow to protect the pump.	Detailed review completed.
MOV-39	RCIC MOV 39 (RCIC suction valve from the suppression pool) fails to open on demand. This valve is required to open when the RCIC pump suction is transferred from the CST to the torus.	Detailed review completed.
MOV-41	RCIC MOV 41 (RCIC suction valve from the suppression pool) fails to open on demand. This valve is required to open when the RCIC pump suction is transferred from the CST to the torus.	Not included because valve has adequate design margin to open when required.
MOV-64-31	MOV 64-31 (manual makeup valve from the CST to hotwell) fails to open on demand.	Failure of this valve will prevent make-up from the hot-well to the CST. The loss of this valve would not be safety significant and there are no indications that there is low margin on for this valve
Offsite Transmission System	Offsite Transmission System: preferred source of power to the 4160V safety buses; must remain stable and available following the trip of the VY generator.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Operator Bypasses the MSIV Isolation Interlocks	Operator Bypasses MSIV Isolation Interlocks. The justification is the decrease in the Allowable Action Time for the operators at the EPU level (CPPU). It is based on input from the Human Performance technical staff, Appendix A of NUREG 1764 (Generic Human Actions that are Risk Important), and GE document NEDC-330090P, Table 10-5 (Assessment of Key Operator Action).	The allowable action time to bypass the MSIV low-low level isolation interlocks is based upon the time it would take to reach the RPV low-low level setpoint for an ATWS with no injection. Validation studies by the licensee have shown that the task would be accomplished for transient and LOCA events within the required time. The margin to accomplish the task is adequate, for current and CPPU conditions, given other operational factors and steps in the EOPs which must be taken into account (e.g., a high main steam line radiation isolation signal maintaining the valves closed). Operators train and are evaluated and tested on a regular basis for this scenario further reducing the likelihood that the task would not be completed in the time required.
Operator Inhibits ADS	Operator action to inhibit ADS. The justification is the decrease in the Allowable Action Time for the operators at the EPU level (CPPU). It is based on input from the Human Performance technical staff, Appendix A of NUREG 1764 (Generic Human Actions that are Risk Important), and GE document NEDC-330090P, Table 10-5 (Assessment of Key Operator Action).	The operator action to inhibit ADS is one of the first actions taken by the operators under certain transient conditions in the EOPs. The allowable action time is based on the time to reach the vessel level low-low set point for ATWS without injection plus two minutes for the ADS timer. Validation studies and operator observation in the control room have demonstrated that the action would be accomplished in less than 3 minutes. The margin to complete the task is not significantly changed under CPPU conditions. Additionally, operators are trained and tested regularly in this EOP action step.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Passive Failure of Feedwater Piping	Review effect of increased feedwater flow on flow-accelerated corrosion rates following the power uprate.	Detailed review completed.
PB IR 2002-011 (HPCI Functional Issue)	Peach Bottom Finding for IR 50-277/2002-011 (8/5/02) - Finding Related to High Pressure Coolant Injection Function (may apply to RCIC system at VY).	Detailed review completed.
PCV-23	RCIC PCV 23 (RCIC air operated lube oil temperature control valve) fails to open on demand. This valve uses instrument air to control its setpoint and fails fully open on a loss of instrument air. This valve is required to provide cooling water, at the correct pressure, to the RCIC pump lube oil cooler when the RCIC pump is operating.	Detailed review completed.
PS-67	Spurious RCIC low suction pressure trip signal. This instrument will cause the RCIC pump to trip in the event of low pump suction pressure. Spurious trips will result in a loss of RCIC flow.	Not included because there is significant margin in the setpoint to prevent a spurious trip.
PSH-72A/B	Spurious RCIC turbine exhaust high pressure trip. This instrument will trip the RCIC pump in the event of high pressure in the exhaust steam line. Spurious trips will result in a loss of RCIC flow.	Not included because there is significant margin in the setpoint to prevent a spurious trip.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
PT-59/60	RCIC pump discharge pressure. This instrument is associated with the RCIC turbine control logic.	Not included because there is significant margin in the setpoint.
PT-68	Spurious low steam line pressure signal. This instrument will isolate steam flow to the RCIC turbine in the event of low steam supply pressure, indicating a steam line break. Spurious isolation would result in a loss of RCIC flow.	Not included because the pressure switch setpoint has significant margin to prevent a spurious pump trip.
PT-70	Spurious RCIC trip on high turbine exhaust pressure signal. Component ID is PT-70. Include exhaust rupture disks S3 and S4. This instrument will trip the RCIC pump in the event of high pressure in the exhaust steam line. Spurious trips will result in a loss of RCIC flow.	Not included because there is significant margin in the setpoint and operating pressure to prevent a spurious trip.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Manual operation of MOV 64-31	Operator fails to manually open MOV 64-31 (used to manually transfer makeup from the CST to the condenser).	The operator action to manually open valve MOV 64-31, Hotwell Emergency Makeup Valve, is performed in the main control room. The action is required when turbine bypass is not available (during an MSIV closure event). In that case automatic makeup to the hotwell from the Condensate Storage Tank (CST) may not be sufficient to keep up with reactor vessel makeup requirements (feedwater pumps providing vessel level makeup). Validation studies and operator observations have estimated a 1 minute time to manipulate the valve from the control room. If the valve is required to be opened from the field the estimates are less than 15 minutes, however, other EOP mitigation strategies such as use of low pressure ECCS pumps, would assure core coverage if the valve could not be opened.
RB/Torus Vacuum Breakers	Reactor Building to Torus vacuum breakers. The vacuum breakers are required to open to prevent a vacuum in the containment. These also must remain closed to ensure containment integrity and to prevent loss of overpressure for ECCS NPSH.	Detailed review completed.
RCIC Pump P-47-1A and Turbine TU-2-1-A	RCIC pump P-47-1A fails to start on demand. This sample includes the turbine driven RCIC pump, the governor valve, and trip throttle valve.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Reactor Feed Pump	Failure of the feedwater pump will fail to deliver flow required for normal operation or to mitigate an accident. Prior to EPU 2 of three feedwater pumps are required to support the Feedwater system requirements. As such there is a 50% spare capability. For EPU three pumps are required to operated due to the increase requirements of feedwater flow.	Detailed review completed.
RHR Pump	Review RHR pump NPSH calculation, associated suction strainers, bubble ingestion, and torus vortexing issues.	Detailed review completed.
Safety Valve (New)	Addition of third main steam safety valve for power uprate. Failure of SSV to open and relieve pressure during transients or small/medium break LOCA.	Detailed review completed.
SLC Initiation with Condenser Failed	Operator fails to initiate SLC with the main condenser failed. The justification is the decrease in the Allowable Action Time for the operators at the EPU level (CPPU). It is based on input from the Human Performance technical staff, Appendix A of NUREG 1764 (Generic Human Actions that are Risk Important), and GE document NEDC-330090P, Table 10-5 (Assessment of Key Operator Action).	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Spurious High Steam Line Space Temperature Trip	Spurious RCIC trip on high steam line space temperature (instrument TS 79 through 82). These instruments would result in isolation of the steam flow to the RCIC turbine in the event of a steam line break. A spurious trip would result in loss of RCIC flow.	Not included because there is significant margin between the setpoint and the operating temperature to prevent a spurious trip.
Spurious High Steam Tunnel Temperature Trip	Spurious RCIC trip on a high steam tunnel temperature trip signal. These instruments would result in isolation of the steam flow to the RCIC turbine in the event of a steam line break. A spurious trip would result in loss of RCIC flow.	Not included because there is significant margin between the setpoint and the operating temperature to prevent a spurious trip.
Spurious Reactor High Level Trip	Spurious high reactor water level signal (trip could affect both the RCIC pump or feed water pump). These instruments would result in tripping the RCIC turbine in the event of high RPV level. A spurious trip would result in loss of RCIC flow.	Excluded because HPCI and the RFP trip signals are provided by different instruments and the probability of a simultaneous failure of these instruments is extremely low.
SR-26	SR-26 (RCIC supply to lube oil cooler relief valve) fails open. This component is designed to protect the RCIC lube oil cooler and may be important on a loss of IA when the flow control valve fully opens (based on interview with RCIC System Manager).	Detailed review completed.
SRVs	Safety relief valves allow the reactor to be depressurized.	Detailed review completed.

SSC/OA/OE	Description	Detailed Review Completed / Basis For Exclusion
Vernon Tie Line	Operator monitoring of Vernon tie line to ensure availability as a station blackout source.	Detailed review completed.

ATTACHMENT B

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

D. Amidon	EFIN Engineer
M. Arnett	Systems Engineer - Electrical
K. Bronson	General Manager
F. Burger	Corrective Action
J. Callaghan	Design Engineering Manager
M. Castronova	Design EFIN Supervisor
J. Devincentis	Licensing Manager
J. Dreyfuss	Director of Engineering
E. Duda	Power Uprate Engineer
N. Fales	Systems Engineer - FW and Condensate
K. Farabaugh	Systems Engineering Supervisor
J. Fitzpatrick	Design Mechanical/Structural Engineering - FAC
M. Flynn	Design Engineer – Electrical
D. Girroir	Systems Engineering Supervisor
S. Goodwin	Design Mechanical/Structural Engineering Supervisor
A. Graves	Design Admin Assistant
C. Hansen	Design Engineer - Components
A. Haumann	Design Engineer – Electrical
B. Hobbs	Power Uprate – Engineering Supervisor
M. Janus	Design Engineer – Electrical
P. Johnson	Design Engineer - Electrical
J. Kritzer	Operations/Reactor Engineer
M. Lefrancois	Systems Engineering Supervisor
P. Longo	Design Engineer - Components
L. Lukens	Systems Engineering Supervisor
M. McKenney	Maintenance Support Engineering
J. Melvin	Systems Engineer – SLC
M. Metell	Entergy-Vermont Yankee Response Team Leader
B. Naeck	Systems Engineer - RCIC
C. Nichols	Power Uprate Engineering Manager
T. O'Connor	Design Engineer – Mechanical/Structural
M. Palionis	PRA Engineer
P. Perez	Design Engineer – Fluid Systems
P. Rainey	Design Engineer – Fluid Systems
A. Robertshaw	Design Engineer – Fluid Systems
J. Rogers	Design Fluid Systems Engineering Supervisor
R. Rusin	Design Engineering Supervisor - Components
B. Slifer	Power Uprate Engineer
J. Stasolla	Systems Engineer – Electrical

J. Taylor	Corrective Action
J. Thayer	Site Vice President
G. Thomas	Power Uprate – Contractor Interface
J. Twarog	Operations Shift Engineering Supervisor
R. Vibert	Design Electrical Engineering Supervisor
C. Wamser	Operations Manager
R. Wanczyk	Director of Nuclear Safety
G. Wierzbowski	Systems Engineering Manager
A. Wonderlick	Systems Engineer – Electrical

Other

W. Farnsworth	Training Coordinator - REMVEC / National Grid
D. Goodwin	Operations Supervisor US-GEN
W. Houston	Manager of Transmission - REMVEC / National Grid
W. Sherman	Vermont State Nuclear Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000271/2004008-04	URI	Ungrounded 480 VAC Electrical System. (Section 4OA5.2.1.1.b.3)

Opened and Closed

05000271/2004008-01	NCV	Availability of Power from the Vernon Station. (Section 4AO5.2.1.1.(b).1)
05000271/2004008-02	NCV	Procedures for Assessing Off-site Power Operability. (Section 4AO5.2.1.1.(b).2)
05000271/2004008-03	NCV	Degraded Relay Setpoint Calculations. (Section 4AO5.2.1.1.(b).3)
05000271/2004008-05	NCV	Cooling Water Supply Portion of RCIC Not Installed per Design Basis. (Section 4AO5.2.1.2.(b).1)
05000271/2004008-06	NCV	Failure to Correct Non-Conforming RCIC Pressure Control Valve. (Section 4A05.2.1.2(b).2)

05000271/2004008-07	NCV	Failure to Implement Adequate Design Control for Condensate Storage Tank Temperature. (Section 4AO5.2.1.7.(b))
05000271/2004008-08	NCV	Failure to Revise Safe Shutdown Capability Analysis Report. (Section 4AO5.2.2.(b))
05000271/2004008-09	NCV	Failure to Establish Adequate MOV Periodic Test Program. (Section 4AO5.2.3.(b))

LIST OF DOCUMENTS REVIEWED

Procedures and Tests

Emergency Operating Procedures

EOP-1 - RPV Control, Rev. 2
EOP-2 - ATWS, Rev. 4
EOP-3 - Primary Containment Control, Rev. 3
EOP-5 - RPV-ED, Rev. 3

Operating Procedures

OP-0023, Installation and Testing of Cable and Conduit, Rev. 8
OP-2113, Main and Auxiliary Steam, Rev. 20
OP-2114, Operation of the Standby Liquid Control System, Rev. 22
OP-2115, Primary Containment, Rev. 44
OP-2116, Secondary Containment Integrity Control, Rev. 19
OP-2119, Nitrogen Supply System, Rev. 13
OP-2121, Reactor Core Isolation Cooling System (RCIC), Rev. 29
OP-2124, Residual Heat Removal System, Rev. 52
OP-2140, 345 KV Electrical System, Rev. 25
OP-2141, 115KV Switchyard, Rev. 17
OP-2142, 4KV Electrical System, Rev. 21
OP-2145, Normal 125 VDC Operation, Rev. 24
OP-2149, Normal 24 VDC Operation, Rev. 7
OP-2170, Condensate System, Rev. 23
OP-2172, Feedwater System, Rev. 23
OP-3126, Shutdown Using Alternative Methods, Rev. 16
OP-4255, Calibration of 4kV Bus Degraded Grid Undervoltage Relays, Rev. 11
OP 5217, MOV Motor Control Center (MC2) Testing, Rev. 2
OP 5287, Evaluation of MOV Motor Control Center (MC2) Testing, Rev. 2
OP 5219, Diagnostic Testing of Motor Operated Valves, Rev. 12
OP 5220, Limitorque Operator PM, Rev. 25

Operational Transient

OT-3113, Reactor Low Level, Rev. 13
OT-3114, Reactor High Level, Rev. 13
OT-3115, Rx Low Pressure, Rev. 8
OT-3116, Rx High Pressure, Rev. 8
OT-3121, Inadvertent Opening of a Relief Valve, Rev. 13
OT-3122, Loss of Normal Power, Rev. 20

Other

ENN-OP-104, Operability and Determination Procedure, Rev. 2
ENN-DC-325, Component Performance Monitoring, Rev. 0
ENN-DC-151, PSA Maintenance and Update, Rev. 0
AP 6038, Component Level Review of Vermont Yankee Motor-Operated Valves (MOVs), Rev.1
AP 6039, Electrical Design Basis Review of Vermont Yankee Motor-Operated Valves (MOVs), Original Issue
AP 6037, System and Functional Design Basis Review of Vermont Yankee Motor-Operated Valves (MOVs), Original Issue
AP 6040, Vermont Yankee Motor-Operated Valve Electrical Configuration, Original Issue
AP 6041, Vermont Yankee Engineering Evaluations of MOV Diagnostic Testing and Feedback of Results into MOV Component Calculations, Rev. 1
PP 7004, Vermont Yankee Nuclear Power Station Motor Operated Valve Program, Rev. 1
PP 7005, Periodic Verification of Motor Operated Valves, Original Issue
CRP 9-8, Main Control Room Overhead Alarm Panel, Vernon BKR 3V4 Trip/Bus Voltage Low
ON 3155, Loss of Auto Transformer, Rev. 9

Calculations and Studies

Vendor Calculations

RCIC hydraulic calculations (VYE-1064 and VYE-1423)
Structural Integrity Inc. Report SIR-04-020 Rev 0, File VY-10Q-401, Updated Stress and Fatigue Analysis for the Vermont Yankee Feedwater Nozzles, March 2004
Structural Integrity Inc. File VY10Q-302 Loads and Transient Definitions, Rev. 0
Structural Integrity Inc. Calculation Package VY-10Q-303, Uprated Feedwater Nozzle Stress and Fatigue Analysis, Rev. 0
Structural Integrity Inc. Calculation VY-10Q-301 Feedwater Nozzle Finite Element Model and Heat Transfer Coefficients, Rev. 0
Vendor Calculation DC-A34600-03, RHR and CS Suction Strainer Bubble Ingestion, Rev. 0

Vermont Yankee Calculations

VYC-415, Appendix R RCIC, HPCI, and ECCS Room Cooling, Rev. 0
VYC-462C, RCIC Steam Line Area High Temperature Setpoint, Rev. 0, and CCN 01
VYC-706, Condensate Storage Tank Level (RCIC) Monitoring, Rev. 1, CCN 01 and 02

VYC-709, RCIC System Flow Control and Indication Loop Accuracy, Rev. 1
VYC-715, Degraded Bus Voltage Monitoring loop Accuracy, Rev. 1
VYC-808, Core Spray and RHR Pump Net Positive Suction Head Margin Following a LOCA with Fibrous Debris on the Intake Strainers, Rev. 0, and CCN 4, 5 and 6 and its supporting references
VYC-830, Voltage Drop Calculations for VY Distribution Panels DC-1 and DC-2, Rev. 9 and CCN No. 5.
VYC-1005, Crack Growth Calculation for the Vermont Yankee FW Nozzles, Rev. 2
VYC-1053, Motor Operated Valve (MOV) Voltage Analysis, Rev. 8 and CCN 02
VYC-1088, Vermont Yankee 4160/480 Volt Short Circuit/ Voltage Study, Rev. 3
VYC-1293, System Level Review of Reactor Core Isolation Cooling MOVs for GL 89-10, Rev. 3
VYC-1347, Main Steam Tunnel Heatup Calculation, Rev. 0
VYC-1349, 125V Direct Current DC Voltage Drop Study, Rev. 2 and CCN 05
VYC-1512, Station Blackout Voltage Drop and Short Circuit Study, Rev. 2
VYC-1700, 4.16kV Bus Protective Relay Settings Verification, Rev. 1
VYC-1726, Reactor Core Isolation Cooling Pump Test Acceptance Values, Rev. 1 and CCN 01
VYC-1816, RCIC Pump Net Positive Suction Head (NPSH), Rev. 0 and CCN 01
VYC-1825, Analysis of Suppression Pool Temperature for Relief Valve Discharge Transients, Rev. 0 and CCN 1
VYC-1844, HPCI and RCIC Vortex Height, Rev. 1
VYC-1857, Fast and Residual Voltage Bus Transfer Analysis, Rev. I
VYC-1920, RHR and CS Suction Strainer Vortex/Minimum Submergence, Rev. 0 (DE&S Calculation DC-A34600-02 Rev. 0)
VYC-1924, Vermont Yankee ECCS Suction Strainer Head Loss Performance Assessment, RHR and CS Debris Head Loss Calculations, Rev. 0 (DE&S Calc DC-A32600-006 Rev. 0)
VYC-1950, Hydrodynamic Mass and Acceleration Drag Volume of Vermont Yankee ECCS Strainers, Rev. 0
VYC-1959, Analysis of Tests for Investigation (of) the Effects of Coatings Debris on ECCS Strainer Performance for Vermont Yankee, Rev. 1 (DE&S Report ITS/VY-98-01, Rev.1)
VYC-2153, 125 VDC Battery A-1 Electrical System Calculation, Rev. 0 and CCN 03
VYC-2154, 125 VDC Battery B-1 Electrical System Calculation, Rev. 0
VYC-2314, Minimum Containment Overpressure for Non-Loca Events, Rev. 0 and CCN 01 and 02
VYPC 98-010, Component Level Review of Reactor Core Isolation Cooling (RCIC) MOVs for GL 89-10, Rev. 2

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Franklin Institute Technical Report F-C2653-01 Design and Stress Analysis of the Vermont Yankee NPS Clean-up / Feedwater Recombination Tee
General Electric (GE) Topical Report T0900
GE-NE-0000-0009-9951-01 Rev 1, Task 0302 Reactor Vessel Integrity Stress Analysis (Excludes the radius of the forging)

GE-NEDC-330090P, Assessment of Key Operator Actions, Table 10-5
Strainer Head Loss Performance Assessment, RHR and CS Debris Head Loss, Rev 0.
VYNPS:EPU T0400: DBA-LOCA for Long Term NPSH Evaluation
Yankee Uprate System Impact Study, dated November 11, 2003

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CR-96-117	CR-00-1575	CR-02-1860	CR-04-448
CR-96-129	CR-00-1596	CR-02-2193	CR-04-815
CR-96-136	CR-01-880	CR-02-2194	CR-04-1234
CR-98-467	CR-01-889	CR-02-2716	CR-04-1484
CR-98-1171	CR-01-890	CR-02-2733	CR-04-1522
CR-98-2066	CR-01-1007	CR-02-2942	CR-04-2600
CR-99-175	CR-01-1232	CR-03-441	CR-04-2621
CR-99-618	CR-01-1340	CR-03-962	CR-04-2623
CR-00-94	CR-01-1834	CR-03-1491	CR-04-2644
CR-00-306	CR-01-2084	CR-03-1855	CR-04-2723
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CR-00-1509	CR-01-2214	CR-03-2810	CR-04-2799
CR-00-1567	CR-02-151	CR-04-433	CR-04-2802

Drawings

Drawing B-191301 Sh. 1150, Core Spray System "B" Aux. Relays Sh 1, Rev. 13
Drawing B-191301 Sh. 306, 4kV SWGR #3 Instr & Relaying, Rev. 16
Drawing B-191301 Sh. 317, 4kV SWGR Aux. Relay Ckt., Rev. 10
Drawing B-191301 Sh. 327, 4kV SWGR #3 Tie to 4kV SWGR #1 Bkr. #3T1, Rev. 8.
Drawing B-191301 Sh. 328A, 4Kv SWGR #3 Compt, 10 Diesel Generator DG1-1B Bkr & LNP Ckt., Rev. 11
Drawing G-191157 Sheet 2 Location L-9, Flow Diagram Condensate, Feedwater and Air Evacuation Systems, Rev. 5
Drawing G-191174, Sheet 2, Flow Diagram - Reactor Core Isolation Cooling, Rev. 23
Drawing B-191261, Sheet 26C, Impulse Piping to Rack RK-6, Rev. 6
Drawing G-191298 Sh.1, Main One Line Diagram, Rev. 32
Drawing G-191298 Sh.2, Main One Line Phasor Diagram, Rev. 8
DS801-2, Generator SN 180X383 Reactive Capability Curve, dated February 11, 2003
Drawing 6202-001, General Plan Pressure Suppression Containment Vessel C Residual Heat Removal System - Bubble Ingestion from Safety Relief Valve and LOCA, Rev. 3

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CR-VTY-2001-00966; Leak Rate Test Results Exceeded the Acceptance Criteria, Originated: 5/04/2001, Closed: 6/29/2001
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CR-VTY-2004-2596; The Design Basis for Degraded Grid UV Relay not Adequately Documented in Calculation, Originated: 8/16/2004, Closed: Still Open

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EDCR 81-22 in accordance with NUREG-0737, Item II.K.3.22
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EDCR 94-406, MOV Improvements, dated July 13, 1995
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Modification Package MM-2003-016, Reactor Recirculation System Run Back For Feedwater and Condensate System Transients
Modification Package MM-2004-015, Improve SLC Relief Valve Tolerances to Meet New SLC System Operating Pressure Requirements
Vermont Yankee Design Change VYDC 2003-013, Addition of 3rd Main Steam Safety Valve, dated 7/9/2003
Vermont Yankee Design Change VYDC 2001-003, RCIC Turbine Exhaust Check Valve Replacement, dated 10/28/2004

Correspondence

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Memorandum, E. Betti to S. Miller, Monthly Feedwater Leakage Monitoring Data Report Analysis, dated December 6, 1993
Letter FVY 82-105, VY to NRC, Feedwater Spargers - Response to NRC's Request for Additional Information, dated September 21, 1982
Letter BVY 94-07, VY to NRC, Request for Relief from NUREG-0619 Inspection Requirements, dated February 11, 1994
Letter NVY 95-142, VY to NRC, Feedwater Nozzle Inspection Relief Request - Vermont Yankee Nuclear Power Station (TAC No. M92940), dated October 12, 1995
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Letter BVY 01-02, VY to NRC, Alternative Feedwater Nozzle Inspection, dated January 22, 2001
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Letter BVY 96-143, VY to NRC, Vermont Yankee 60-day Response to Generic Letter 96-05, dated November 15, 1996
Letter BVY 97-36, VY to NRC, Vermont Yankee 180-day Response to Generic Letter 96-05, dated November 15, 1996
Summary of Changes in Leak Detection Data, Report Generated August 30, 2004
Summary of Changes in Leak Detection Data, Report Generated September 1, 2004
GE Letter VYNPS-AEP-346 Revisions 0, 1 and 2

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Event Report 20030340, Root Cause Analysis, The Outboard Seal on RFP “C” Failed

Other Documents

Generic Letter (GL) 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance,” dated June 28, 1989
Generic Letter (GL) 96-05, “Periodic Verification of Design-Basis Capability of Safety-Related Power Operated Valves,” dated September 18, 1996
Information Notice (IN) 2001-13, “Inadequate Standby Liquid Control System Relief Valve Margin, dated August 10, 2001.
Operational Decision-Making Issue (ODMI) Action Plan 2003-1812
NRC SER, Degraded Grid Voltage Protection for Class 1E Power Systems, dated March 31, 1986
Regulatory Guide 1.82, “Water Sources for Long-Term Recirculation Cooling following a Loss-of-Coolant Accident,” Revision 3, dated November 2003
Vermont Yankee Updated Final Safety Analysis Report (UFSAR), Revision 18
Vermont Yankee Individual Plant Examination (IPE) Document
Vermont Yankee Appendix R Safe Shutdown Capability Analysis (SSCA), dated December 23, 1999
Vermont Yankee Technical Specifications, through Amendment No. 219

LIST OF ACRONYMS

AC	Alternating Current
ASME	American Society of Mechanical Engineers
CR	Condition Report
CST	Condensate Storage Tank
EPU	Extended Power Uprate
EOP	Emergency Operating Procedure
FAC	Flow Assisted Corrosion
GE	General Electric
GL	Generic Letter
HPCI	High Pressure Coolant Injection
kV	Kilovolt
LER	Licensee Event Report
MCC	Motor Control Center
MOV	Motor-Operated Valve
NCV	Non-Cited Violation
NPSH	Net Positive Suction Head
NRC	US Nuclear Regulatory Commission
OD	Operability Determination
psig	Pounds Per Square Inch Gauge
PRA	Probabilistic Risk Assessment

PUSAR	Power Uprate Safety Analysis Report
RAW	Risk Achievement Worth
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
ROP	Reactor Oversight Process
SBO	Station Blackout
SDP	Significance Determination Process
SLC	Standby Liquid Control
SPAR	Simplified Plant Analysis Risk
SRV	Safety/Relief Valve
TE	Technical Evaluation
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
V	Volt
VY	Vermont Yankee
VY SSCA	Vermont Yankee Safe Shutdown Capability Analysis