50-261

October 29, 1997

Mr. James Davis
Nuclear Energy Institute
1775 Eye Street, N.W.
Washington, D.C. 20006-3708

Dear Mr. Davis:

On October 24, 1997, the staff issued a license amendment for the H.B. Robinson 2 conversion to the improved Standard Technical Specifications (STS). This is the 12th conversion to the improved STS, which will result in 16 units operating with these technical specifications. The Robinson conversion is unique in that it served as a pilot for the development by NRC of a new format for the safety evaluation (SE) which should result in staff resource savings and more timely reviews, while at the same time providing a clearer and more succinct product. In addition, the Robinson conversion amendment included a new license condition to ensure that surveillance schedules are not perturbed by the conversion to the improved STS. This amendment also contains a licensee condition to enforce licensee commitments to relocate items removed from the technical specifications to the appropriate licensee-controlled documents. This latter license condition is similar to one that is now being used by the staff for other relocations.

A key feature of the revised SE is a series of tables containing summary descriptions and categories of the changes to the technical specifications as a result of the conversion. It is our expectation that licensees will provide these tables to the staff late in the review process as the staff starts to write the SE. No change in the format of the initial submittal is being requested. However, licensees should be aware of this expectation so that they can ensure that their data bases and word processing can easily generate these tables from existing submittal material at the appropriate point in time. We request that you make the availability of this amendment and revised SE format widely known throughout the industry and include a reference to it in your planned update to NEI 96-06.

Sincerely,

Original Signed By

William D. Beckner, Chief
Technical Specifications Branch
Associate Director for Projects
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

October 29, 1997

Mr. James Davis
Nuclear Energy Institute
1775 Eye Street, N.W.
Washington, D.C. 20006-3708

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On October 24, 1997, the staff issued a license amendment for the H.B. Robinson 2 conversion to the improved Standard Technical Specifications (STS). This is the 12th conversion to the improved STS, which will result in 16 units operating with these technical specifications. The Robinson conversion is unique in that it served as a pilot for the development by NRC of a new format for the safety evaluation (SE) which should result in staff resource savings and more timely reviews, while at the same time providing a clearer and more succinct product. In addition, the Robinson conversion amendment included a new license condition to ensure that surveillance schedules are not perturbed by the conversion to the improved STS. This amendment also contains a licensee condition to enforce licensee commitments to relocate items removed from the technical specifications to the appropriate licensee-controlled documents. This latter license condition is similar to one that is now being used by the staff for other relocations.

A key feature of the revised SE is a series of tables containing summary descriptions and categories of the changes to the technical specifications as a result of the conversion. It is our expectation that licensees will provide these tables to the staff late in the review process as the staff starts to write the SE. No change in the format of the initial submittal is being requested. However, licensees should be aware of this expectation so that they can ensure that their data bases and word processing can easily generate these tables from existing submittal material at the appropriate point in time. We request that you make the availability of this amendment and revised SE format widely known throughout the industry and include a reference to it in your planned update to NEI 96-06.

Sincerely,

William D. Beckner

William D. Beckner, Chief
Technical Specifications Branch
Associate Director for Projects
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

August 27, 1997

Mr. Donald A. Reid
Vice President, Operations
Vermont Yankee Nuclear Power Corporation
Ferry Road
Brattleboro, VT 05301

SUBJECT: VERMONT YANKEE DESIGN INSPECTION (NRC INSPECTION REPORT NO. 50-271/97-201)

Dear Mr. Reid:

From May 5 through June 13, 1997, the staff of the U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Reactor Regulation (NRR), Special Inspection Branch, performed a design inspection of the low pressure coolant injection (LPCI) and residual heat removal service water (RHRSW) systems at the Vermont Yankee Nuclear Power Station (VY). The purpose of the inspection was to evaluate the capability of the selected systems to perform the safety functions required by their design bases, as well as the adherence of the systems to their respective design and licensing bases, and the consistency of the as-built configuration and system operations with the final safety analysis report (FSAR). The team discussed significant findings of the inspection with your staff during the team exit meeting on June 13, 1997, and during the public exit meeting on July 1, 1997.

As discussed in the enclosed report, the team concluded that the LPCI and RHRSW systems were capable of performing their intended safety functions. Overall, the design engineers of the Yankee Atomic Electric Company, who provided engineering services to VY, had excellent knowledge and capabilities. Nonetheless, the team identified concerns in the following areas.

First, the team identified several operability issues which required prompt corrective actions by your staff. For example, the team found that the non safety-related pressure regulator could result in loss of service water to the diesel generators. Also, the team questioned the operability of your RHR pumps with minimum pump flow considerably less than what the pump vendor recommended for continued operation. Additionally, the team raised concerns regarding the operability of the RHR pumps while in the torus cooling mode and the operability of the RHR heat exchangers on the basis of improperly performed tests. Your initial corrective actions to address these issues were acceptable.

Secondly, the team had concerns with your past resolution to several engineering issues such as operation of the unit with the torus temperature above the analyzed region and various discrepancies in the plant's Technical Specifications. In particular, we were concerned with your long term resolution to operation of your RHR pump with less than recommended minimum pump flow during a design basis event.

Based on the understanding of your current design bases efforts, the team concluded that it was unlikely that you would have uncovered some of the issues identified in this report. Based on the conversation at the exit meeting, we understand that your staff will be re-examining your design bases program. Region I intends to review this issue when they inspect the findings in this report.

Please provide a schedule, within 60 days, detailing your plans to complete the corrective actions required to resolve the open items listed in Appendix A to the enclosed report. This schedule will enable the NRC staff to plan for the reinspection and closeout of these items.

In addition, as with all NRC inspections, we expect that your staff will evaluate the applicability of the results and specific findings of this inspection to other systems and components throughout the plant.

In accordance with Title 10, Section 2.790(a) of the *Code of Federal Regulations*, a copy of this letter and the enclosure will be placed in the NRC's Public Document Room. Any enforcement action resulting from this inspection will be handled by NRC Region I via separate correspondence.

Should you have any questions concerning the enclosed inspection report, please contact the project manager, Mr. Kahtan Jabbour at (301) 415-1496, or the inspection team leader, Mr. James A. Isom, at (301) 415-1109.

Sincerely,

Stuart A. Richards, Chief
Special Inspection Branch
Division of Inspection and Support Programs
Office of Nuclear Reactor Regulation

Docket No.: 50-271

Enclosure: Inspection Report 50-271/97-201

cc: see next page

Based on the understanding of your current design bases efforts, the team concluded that it was unlikely that you would have uncovered some of the issues identified in this report. Based on the conversation at the exit meeting, we understand that your staff will be re-examining your design bases program. Region I intends to review this issue when they inspect the findings in this report.

Please provide a schedule, within 60 days, detailing your plans to complete the corrective actions required to resolve the open items listed in Appendix A to the enclosed report. This schedule will enable the NRC staff to plan for the reinspection and closeout of these items.

In addition, as with all NRC inspections, we expect that your staff will evaluate the applicability of the results and specific findings of this inspection to other systems and components throughout the plant.

In accordance with Title 10, Section 2.790(a) of the *Code of Federal Regulations*, a copy of this letter and the enclosure will be placed in the NRC's Public Document Room. Any enforcement action resulting from this inspection will be handled by NRC Region I via separate correspondence.

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Sincerely,

ORIGINAL SIGNED BY Donald P. Norkin

Stuart A. Richards, Chief
Special Inspection Branch
Division of Inspection and Support Programs
Office of Nuclear Reactor Regulation

Docket No.: 50-271

Enclosure: Inspection Report 50-271/97-201

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Please provide a schedule, within 60 days, detailing your plans to complete the corrective actions required to resolve the open items listed in Appendix A to the enclosed report. This schedule will enable the NRC staff to plan for the reinspection and closeout of these items.

In addition, as with all NRC inspections, we expect that your staff will evaluate the applicability of the results and specific findings of this inspection to other systems and components throughout the plant.

In accordance with Title 10, Section 2.790(a) of the *Code of Federal Regulations*, a copy of this letter and the enclosure will be placed in the NRC's Public Document Room. Any enforcement action resulting from this inspection will be handled by NRC Region I via separate correspondence.

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Stuart A. Richards, Chief
Special Inspection Branch
Division of Inspection and Support Programs
Office of Nuclear Reactor Regulation

Docket No.: 50-271

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Please provide a schedule, within 60 days, detailing your plans to complete the corrective actions required to resolve the open items listed in Appendix A to the enclosed report. This schedule will enable the NRC staff to plan for the reinspection and closeout of these items.

In addition, as with all NRC inspections, we expect that your staff will evaluate the applicability of the results and specific findings of this inspection to other systems and components throughout the plant.

In accordance with Title 10, Section 2.790(a) of the *Code of Federal Regulations*, a copy of this letter and the enclosure will be placed in the NRC's Public Document Room. Any enforcement action resulting from this inspection will be handled by NRC Region I via separate correspondence.

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Sincerely,

Stuart A. Richards, Chief
Special Inspection Branch
Division of Inspection and Support Programs
Office of Nuclear Reactor Regulation

Docket No.: 50-271

Enclosure: Inspection Report 50-271/97-201

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DATE	08/22/97		08/ /97		08/22/97		08/ /97			

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OFFICE OF NUCLEAR REACTOR REGULATION

Docket No.:	50-271
License No.:	DPR-28
Report No.:	50-271/97-201
Licensee:	Vermont Yankee Nuclear Power Corporation
Facility:	Vermont Yankee Nuclear Power Station (VY)
Location:	RD 5, Box 169 Brattleboro, VT 05301
Dates:	May 5 through June 13, 1997
Inspectors:	James Isom, Team Leader, Special Inspection Branch Robert Hogenmiller, I&C Engineer* Robert Najuch, Lead Engineer* Dennis Vandeputte, Mechanical Engineer* Arvind Varma, Electrical Engineer* Maty Yeminy, Mechanical Engineer* * Contractors from Stone & Webster Engineering Corporation
Approved by:	Donald P. Norkin, Section Chief Special Inspection Branch Division of Inspection and Support Programs Office of Nuclear Reactor Regulation

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EXECUTIVE SUMMARY

From May 5 through June 13, 1997, the staff of the U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Reactor Regulation (NRR), Special Inspection Branch, conducted a design inspection at Vermont Yankee Nuclear Power Station (VY). The inspection team consisted of a team leader from NRR and five contractor engineers from Stone & Webster Engineering Corporation (SWEC).

The purpose of the inspection was to evaluate the capability of selected systems to perform the safety functions required by their design bases, as well as adherence of the systems to their respective design and licensing bases, and the consistency of the as-built configuration and system operations with the final safety analysis report (FSAR). As the focus of this inspection, the team selected the low pressure coolant injection (LPCI) mode of the residual heat removal (RHR) system and residual heat removal service water (RHRSW) system, on the basis of their importance in mitigating design-basis accidents (DBAs) at VY.

For guidance in performing the inspection, the team followed the engineering design and configuration control portion of Inspection Procedure (IP) 93801, "Safety System Functional Inspection (SSFI)." The team also reviewed portions of the plant's FSAR, design-basis documents, drawings, calculations, modification packages, surveillance procedures, and other documents pertaining to the selected systems.

In preparation for the inspection and in performing previously scheduled engineering reviews, the licensee identified various issues affecting the systems under review. The team identified the following additional issues, some of which raised questions concerning the capability of the selected systems to perform their DBA functions. Where appropriate, the licensee took corrective or compensatory actions to ensure system operability.

- In 1982, the licensee requested a license amendment to modify the plant's technical specifications (TS) by increasing the normal suppression pool (torus) water temperature limit from 90 to 100°F. However, the licensee failed to adequately evaluate the impact of a higher pool temperature following a loss-of-coolant accident (LOCA). Affected analyses included the net positive suction head (NPSH) for pumps, LOCA containment analyses, piping stress and support loads, and equipment qualification. Plant operation with a pool temperature exceeding 90°F for greater than 24 hours had occurred between the time the amendment was granted (1985) and the time the licensee discovered the deficiency (1994). Administrative controls currently preclude plant operation with torus water temperature exceeding 90°F. The team concluded that the plant had operated outside of its design bases during the periods when the torus temperature exceeded 90°F.

- Post-LOCA effects of a change in the initial torus water temperature limit from 90 to 100°F were further complicated by other factors. The licensee reduced the design heat removal capacity of the RHR heat exchanger on the basis of findings identified during the licensee's

internal service water system operational performance inspection (SWOPI) conducted in 1994. The containment analyses performed by General Electric Company (GE) assumed that feedwater flow ceased at time zero; however, in 1996, the licensee determined that the inclusion of feedwater mass and energy would lead to an increase of about 10°F in the peak calculated post-LOCA torus water temperature. The licensee has evaluated the separate effects from each of these changes, and maintained safe operation through administrative controls on torus temperature; however, the licensee has not completed its analysis of the integrated effects of these changes.

- The available RHR pump minimum flow (350 gpm) was considerably less than the (2700 gpm) pump vendor recommended minimum flow required for satisfactory pump operation. Furthermore, the licensee lacked the technical basis for operating the RHR pump with the existing minimum flow rate and had not adequately addressed concerns regarding the safety-related pump minimum flow issue identified in Inspection and Enforcement (IE) Bulletin 88-04. As a result of this inspection, the licensee obtained additional vendor guidance regarding RHR pump minimum flow operation and instituted interim corrective actions to have the operators secure the pump when it operated below the required minimum flow for more than 30 seconds.

- On the basis of the team's concerns regarding heat exchanger test results and instrument inaccuracies, the licensee placed an administrative limit to restrict plant operation to river water temperature below 80°F.

- Portions of the service water system piping and emergency diesel generator auxiliary systems were installed without protection against external missiles. Moreover, the licensee was using a probabilistic risk assessment (PRA) approach as a design basis for lack of protection from tornado-generated missiles, which did not appear consistent with the original licensing documentation.

The team identified the following issues which indicated potential programmatic deficiencies:

- The licensee addressed inconsistencies with the FSAR or TS limits by imposing conservative administrative limits on plant operation. However, the team identified several examples which indicated that the licensee's correction of the licensing documentation was not timely. Examples included the torus pool temperature, RHR heat exchanger capacity, feedwater addition to the containment analysis, and permissible service water out-of-service limitations. In some cases, the licensee incorporated its resolution of an issue into larger programs, such as Improved Technical Specifications; however, this approach appeared to unduly protract the final resolution of these issues.

- When equipment was rendered inoperable for surveillance as required by the plant's TS, the licensee's practice concerning entry into the limiting condition for operation (LCO) was not consistent with the guidance provide in Generic Letter (GL) 91-18. Moreover, no documentation existed with regard to NRC approval of the licensee's position.

- The team identified deviations from GL 89-13 licensing commitments regarding the inclusion of all emergency core cooling system (ECCS) corner room coolers, and determination of the testing frequency necessary to ensure that the design heat removal capability of the RHR heat exchangers would be maintained.

- The team identified weaknesses in the development and control of calculations, and the review and approval processes. The licensee did not adequately maintain electrical design calculations in accordance with Engineering Instruction WE-103, "Engineering Calculations and Analyses." The licensee did not adequately consider the effects of the motor overcurrent relay in its analysis of the Vernon 69 KV switchyard low voltage and RHR pump starts. The team noted a lack of documentation and traceability to previous analyses for exceptions to the electrical separation criteria. Although the licensee was developing an instrument setpoint program, the methodology only recently addressed instrument drift in the analysis.

- There was a weakness concerning the licensee's translation of design criteria and design bases into detailed operating instructions. As a result, operating procedures were inconsistent with design requirements regarding RHR pump minimum flow requirements, permissible RHR pump motor starts, and service water pump operation upon loss of ventilation.

E1.0 Inspection Scope and Methodology

The primary objectives of the design inspection at the Vermont Yankee Nuclear Power Station (VY), were to evaluate the capability of the systems to perform their safety functions as required by design bases and to verify whether the licensee, Vermont Yankee Nuclear Power Corporation (VYNPC), has maintained the plant in compliance with its design and licensing bases. The team selected for inspection the Low Pressure Coolant Injection (LPCI) mode of the Residual Heat Removal (RHR) System and the Residual Heat Removal Service Water (RHRSW) system because of their importance in mitigating design-basis accidents (DBAs) at VY. For guidance in performing the inspection, the team followed the applicable engineering design and configuration control portions of Inspection Procedure (IP) 93801, Safety System Functional Inspection (SSFI).

Appendix A identifies the unresolved items (URIs) and inspection followup items (IFIs) resulting from this inspection. Appendix B lists the individuals who attended the exit meetings on June 13 and July 1, 1997. Appendix C defines the various acronyms used in this report.

E1.1 Low-Pressure Coolant Injection

E1.1.1 System Description and Safety Function

The RHR system was designed as a multi-function system having both normal and accident mitigation functions. The safety function of the LPCI operating mode of the RHR system is to restore and maintain coolant inventory in the reactor vessel after a loss-of-coolant accident (LOCA), such that adequate core cooling is maintained. LPCI operates in conjunction with the other core standby cooling systems (CSCS); including the high pressure coolant injection (HPCI), automatic depressurization system (ADS), and core spray (CS) system . Together, these systems provide adequate core cooling over the complete spectrum of possible break sizes in the reactor coolant system, up to and including a double-ended break of the recirculation pump suction line.

The RHR system consists of two identical closed loops. Each loop contains two parallel pumps; one heat exchanger; and the necessary piping, valves, and instrumentation. The RHR heat exchanger in each loop is cooled by the RHRSW system. In the LPCI operating mode, each RHR loop draws suction from the suppression pool and injects into the core region of the reactor vessel through a reactor recirculation loop. The RHR heat exchangers are initially bypassed (when core cooling is of primary concern), but can be used after a time delay to cool the injection flow. A minimum flow line discharges to the torus suppression pool to provide pump protection when pumping against a closed discharge line. A LOCA signal automatically starts all four RHR pumps and positions valves to direct the coolant injection flow to the reactor vessel. When reactor pressure decreases to a set value, the LPCI injection valves automatically open and, as LPCI discharge pressure exceeds reactor pressure, LPCI flow enters the reactor vessel through the intact recirculation loop(s).

The LPCI system was designed to perform its safety-related function following a LOCA assuming a loss of normal power and a single active failure. In addition, the LPCI equipment, piping, and supports were designed in accordance with Class I seismic criteria.

E1.1.2 **Mechanical**

E1.1.2.1 **Scope of Review**

The mechanical design review of the LPCI system included system walkdowns and discussions with cognizant system and design engineers as well as reviews of the plant's design and licensing documentation. The team reviewed applicable portions of the plant's final safety analysis report (FSAR); technical specifications (TS); as well as the relevant design basis documents (DBDs), flow and process diagrams; other system drawings; calculations; design change requests (PDCR and EDC-R); system operating, inservice and surveillance test procedures and results; event reports (ER); and operating experience reviews (OER).

The team verified the appropriateness and correctness of the licensee's design assumptions, boundary conditions, and system models. The team also assessed whether the design bases were consistent with the licensing bases and verified the adequacy of the licensee's testing requirements. In addition, the team reviewed systems interfacing with the LPCI system to verify that the interfaces were consistent with the LPCI system design and licensing bases and would not have an adverse effect on the LPCI function. The mechanical design review included system thermal/hydraulic performance requirements (such as system capacity, pump net positive suction head, and pump minimum flow) as well as system design pressure and temperature, overpressure protection, component safety and seismic classifications, component and piping design codes and standards, and single failure vulnerability.

E1.1.2.2 **Findings**

a. **Suppression Pool Temperature Design Basis**

In 1982, the licensee requested a license amendment to modify the plant's TS by increasing the normal suppression pool (torus) water temperature limit from 90 to 100°F (Amendment No. 88 received in 1985). This increase in the initial pool water temperature resulted in a peak post-LOCA pool temperature (approximately 176°F) that was about 10°F higher than the maximum value of 166°F presented in FSAR Section 14.6.3. Although the resulting peak post-LOCA pool temperature (176°F) was higher than the pool temperature stated in the FSAR (166°F), the licensee's analysis bounded this temperature increase in that their analysis assumed a peak post-LOCA pool temperature of 176°F. Therefore, the increase in the peak post-LOCA pool temperature resulting from raising the initial pool temperature to 100°F had already been analyzed. The basis for the change solely addressed hydrodynamic load considerations, and did not consider the impact of this amendment on other analyses such as the core standby cooling system (CSCS) pump net positive suction head (NPSH), LOCA containment analyses, CSCS piping stress and support loads, and equipment qualification.

Unrelated to amendment No. 88, the licensee determined that the use of more conservative assumptions with respect to addition of feedwater mass and energy and consideration of intermediate and small break LOCA scenarios - such as the analytical models promulgated by General Electric Company (GE) (as described in NUREG-0783) - would also result in higher post-LOCA pool temperatures. The licensee documented this condition in Potential Adverse Condition (PAC) 96-02, dated March 25, 1996 and determined that in the worst case, the peak post-LOCA pool temperature would not exceed 176°F given an initial pool temperature of 90°F.

The licensee prepared a Basis for Maintaining Operation (BMO) 96-05, dated April 8, 1996 and performed a 10 CFR 50.59 Safety Evaluation as documented in SE 96-008, dated April 8, 1996, to assess the acceptability of an increase in the maximum post-accident pool temperature from 166°F (the value shown in the FSAR) to 176°F. The licensee concluded that the plant could continue to safely operate and that an unreviewed safety question did not exist, as long as the initial pool water temperature did not exceed 90°F.

Before completing the BMO, the licensee established administrative controls to limit the suppression pool temperature to 90°F through a standing order (SO #19) on December 1, 1995. This standing order limit was subsequently revised to limit the pool temperature to 87°F on May 19, 1997 to account for inaccuracy in the instrumentation used to measure pool water temperature. The licensee was still performing the final detailed containment analyses at the end of this inspection.

The inspection team had the following concerns related to this suppression pool temperature issue:

(1) Plant Operation Outside the Design Basis:

The licensee had not evaluated the effects of increased pool temperature from both the increase in the initial pool temperature and from the effects of feedwater energy addition to the operability of the LPCI and core spray pumps. Since license amendment No. 88 was granted on June 6, 1985, the plant has operated with suppression pool water temperature of up to 100°F, even though the safety analyses presented in the FSAR were based on 90°F. A review of plant operating records from 1985 to 1995 identified three separate instances (two 2-day periods in August 1988 and an 8-day period in August 1993) when the measured pool water temperature exceeded 90°F for greater than 24 hours. The plant was outside of its design and licensing bases during those periods. The licensee initiated ER No. 97-0635 to evaluate this concern. This item is designated as **URI 50-271/97-201-01**.

(2) Timeliness of Corrective and Compensatory Actions:

The following licensee actions did not appear to be timely:

- Approximately 9 years elapsed before the licensee identified the deficiencies associated with the 1985 TS change in the pool temperature limit (i.e., from June 6, 1985 when License Amendment No. 88 was issued until May 27, 1994, when licensee memo OPVY 298-94 was issued which addressed the deficiency regarding the licensee's failure to evaluate the impacts of

the higher post-LOCA pool temperature on other analyses such as CSCS pump NPSH, LOCA containment analyses, CSCS piping stress and support loads and equipment qualification).

- The licensee took approximately 18 months (from May 27, 1994 to November 2, 1995) to enter the pool temperature discrepancy into their corrective action system (ER 95-0644). Further, some 19 months elapsed between the time the licensee identified the problem and the time that the licensee imposed an administrative limit on the pool temperature (SO #19 issued December 1, 1995. Additionally, 23 months had elapsed between the time that the licensee had identified the problem and the time that the licensee completed a safety evaluation and operability determination (SE 96-008 and BMO 96-05, both approved on April 8, 1996).

- The RHR system operating procedure OP 2124 was not revised until April 1997 to reflect the pool temperature limit dictated by SO #19 (originally issued December 1, 1995).

- The licensee did not request a TS change after SE 96-008 was approved on April 8, 1996.

The inspection team concluded that the licensee was not timely in its identification and correction of the torus temperature problem. The failure to promptly identify and correct the torus temperature problem represented a weakness with respect to the requirements of 10 CFR Part 50 Appendix B, Criterion XVI, "Corrective Action." This item is designated as **URI 50-271/97-201-02**.

(3) Licensee Event Report

On March 26, 1996, the licensee made a one-hour telephone notification to NRC in accordance with 10 CFR 50.72 (b)(1)(ii)(B). VY reported that the worst-case LOCA containment analysis should consider feedwater flow as indicated in NUREG-0783 and that small and intermediate breaks may result in a higher peak temperature than a large break. This new analysis potentially placed the plant in a condition outside of its design bases. Although the licensee made a one-hour telephone notification, the team found that VY failed to issue a licensee event report (LER) to report this condition. The licensee's failure to issue an LER is considered **URI 50-271/97-201-03**.

b. **RHR Pump NPSH Calculations**

The licensee identified that there were several cases (A2, B2 and C2) in which calculation VYC-808, Rev. 2 yielded a negative NPSH margin for the RHR pumps. The analyses assumed that the RHR pumps were operating under design flow rate condition (7000 gpm), and considered the effects of suction strainer clogging caused by fibrous insulation debris as well as the impact of a 10°F increase in peak calculated post-accident suppression pool water temperature (from 166 to 176°F). To demonstrate acceptable NPSH margins, the licensee used reduced head pump performance conditions that were provided by the RHR pump vendor, Bingham-Willamette (BW), as part of the original pump test data. The team found that the licensee's use of the reduced head pump performance curve was acceptable for this application.

The team identified several errors in the licensee's calculations which reduced the NPSH margin for the RHR pumps. The most significant error was the use of an equation (developed in Calculation VYC-1389, Rev. 0) to calculate the required NPSH as a function of pump flow rate. This equation was a curve fit of the vendor's test data. However, the required NPSH values calculated using the equation were less than the actual test data (by about 0.5 ft.) in the rated flow range and, thus, were not conservative. However, there was conservatism in calculation VYC-808 (e.g. over-estimation of the clean strainer head loss prior to adding allowances for strainer clogging) which would yield additional NPSH margin. The licensee issued ER No. 97-0664 and memo VYs 60/97 dated June 6, 1997 to address the non-conservative NPSH values calculated by the equation. The licensee's resolution of the nonconservative differences between the equation and the test data is designated as **IFI 50-271/97-201-04**.

c. **Non-Conservative LPCI Flow Rates Used in LOCA Analyses**

TS Section 4.5.A.1.c required the performance of a flow rate test during each refueling outage to demonstrate that each LPCI pump delivers 7450 gpm plus or minus 150 gpm (vessel to vessel). Section E of surveillance procedure OP 4124, Rev. 46, specified the flow rate test acceptance criteria as 7300 to 7600 gpm using recorder FR-143. In preparing for the design inspection, the licensee had identified that Calculation VYC-937, Rev. 0 and Rev. 1, used the nominal flow value of 7450 gpm, rather than the minimum acceptance value of 7300 gpm, as the starting point for developing the LPCI flow rate inputs to the LOCA analyses (ER 97-0502). This resulted in higher LPCI flow rate values than may actually exist following a LOCA.

The licensee concluded that the resulting reduction in LPCI flow (approximately 90 gpm) would have a minimal impact on the LOCA analysis results. The use of incorrect and non-conservative LPCI flow inputs in the LOCA analyses represents a weakness with respect to Criterion III of Appendix B to 10 CFR Part 50. This item is designated as **URI 50-271/97-201-05**.

d. **RHR Pump Minimum Flow (IE Bulletin 88-04)**

The team had concerns with the design of the RHR system to provide adequate minimum flow for continuous RHR pump operation. The plant's original design required that each minimum flow line have a nominal design capacity of 350 gpm for each pump. In 1986, Bingham Willamette (RHR pump vendor) notified Vermont Yankee Nuclear Power Corporation (VYNPC) that the minimum flow for the RHR pumps should be increased to 2700 gpm for continuous operation. BW defined continuous operation as more than 2 hours of pump operation in any 24 hours. BW also indicated that the minimum flow can be reduced to 2075 gpm for intermittent operation. However, the RHR system currently accommodates only 350 gpm through the minimum flow piping.

As a result of the team's inspection activities, VY reviewed the precautions regarding minimum flow within the operating and surveillance procedures. The licensee then added a precautionary statement in OP 2124, "Residual Heat Removal System," Rev. 41, to restrict operation of the RHR pump in the minimum flow mode to less than 2 hours of continuous operation in a 24-hour period and indicated that a flow of 2700 gpm is required for periods of 2 hours or more. The licensee also issued

Department Instructions (DIs) 97-102 and 97-100 to clarify OPs 4124 and 2124 by indicating that a system flow rate of 2700 gpm should be promptly established after planned pump starts.

The licensee also obtained additional clarification from the pump vendor, Sulzer Bingham Pumps Inc. (SBPI) - formerly known as Bingham Willamette (BW). In their letter to VY dated May 21, 1997, SPBI stated that the RHR pumps could be operated at 350 gpm for 30 minutes as a *one-time event* in the life of the plant. Additionally, SBPI recommended that RHR pump operation should not be sustained at a flow rate of 350 gpm for any longer than 30 seconds for monthly startup surveillance tests. Further, SBPI believed that the RHR pumps could survive operation at 350 gpm for 30 minutes and continue to function once the flow is increased to 2700 gpm or greater, provided that the pumps were in good mechanical condition. VY informed the team that operator action will limit post-accident minimum flow operation to 30 minutes or less.

The licensee had previously reviewed the RHR pump minimum flow issue in 1986 when BW notified VY of the change in the minimum flow requirement. Having compared the estimated time for pump operation at minimum flow to the total hours which the pump can operate over its life, VY concluded in 1987 that a substantial safety hazard did not exist for the plant. In their analyses, the licensee concluded that intermittent operation of less than 2 hours per 24-hour period over the 40-year design life was equivalent to 29,200 hours. In contrast, the licensee indicated that monthly surveillance testing used the minimum flow path for 15 to 30 seconds, which VY considered negligible.

In the worst case, a small break LOCA may require RHR operation in the minimum flow mode for a maximum of 4 to 5 hours; however, the licensee concluded that a total of 5 hours of operation in the minimum flow mode was considerably less than the 29,200 hours. VY therefore concluded that the pumps would not experience sufficient operating time under the reduced flow conditions for recirculation cavitation failures to develop. However, as a precaution, VY added a statement to procedures OP 2124, "Residual Heat Removal System," Rev. 21, and to OP 4124, "Residual Heat Removal and RHR Service Water System Surveillance," Rev. 22, that pump operation in the minimum flow mode should be minimized.

At approximately the same time period, NRC issued IE Bulletin No. 88-04, "Potential Safety-Related Pump Loss," and requested that all licensees investigate and correct two minimum flow design concerns. One of these concerns was to determine whether the installed minimum flow capacity was adequate for a single pump in operation. Specifically, action item 3 of IE Bulletin 88-04 requested that licensees conduct an evaluation with respect to damage resulting from operation in the minimum flow mode, considering cumulative operating hours in the minimum flow mode over the lifetime of the plant and during the postulated accident scenarios involving the largest time spent in this mode. The evaluation was to consider best current estimates of potential pump damage derived from pertinent test data and field experience, including verification from the pump suppliers that current minimum flow rates were sufficient to ensure that there will be no pump damage from low flow operation. If the test data did not justify the existing capacity of the bypass lines, or if the pump supplier did not verify the adequacy of the current minimum flow capacity, the licensee was to submit a plan to obtain additional test data or modify the minimum flow capacity as needed.

VY responded to IE Bulletin 88-04 through a series of letters. The last of these letters to the NRC (BVY 89-42, dated May 8, 1989) indicated that VY had previously revised plant procedures to reflect the most recent information on minimum flow and no further procedural changes were necessary at that time. Additionally the letter stated that the licensee did not consider it necessary to increase the minimum flow capacity based on the experience of the Boiling Water Reactor Owners Group (BWROG), and based on VY's own experience and their engineering judgment that minimizing time in the minimum flow mode, coupled with the preventative maintenance history would ensure that the pumps remain reliable. With regard to the vendor's experience, VY's response indicated that the minimum pump flow rates were acceptable for surveillance testing; however no data were available to assess operation in the minimum flow range for all time durations.

The team identified the following issues regarding the licensee's response to IE Bulletin 88-04:

- The team concluded that VY's response to IE Bulletin 88-04 lacked the technical basis to conclude that the existing RHR pump minimum flow would be adequate during the postulated accident scenarios during which the RHR pump would operate for several hours under minimum flow conditions. VY's response to Bulletin 88-04 did not provide either the verification from the vendor or test results to demonstrate that RHR pump minimum flow rates were adequate during the postulated accident scenarios. Although the vendor acknowledged that the monthly surveillance tests - limited to 30 seconds at 350 gpm - would probably not result in pump damage, the vendor could not support the assertion that a cumulative arithmetic series of minimum flow events over the life of the plant (29, 200 hours) had the same relationship to pump degradation as the length of a specific event (4 to 5 hours of RHR pump operation during an accident scenario). SBPI also could not predict the mechanical condition or performance of the pumps after a 5-hour run at 350 gpm and did not recommend such a run. The team identified the lack of test data and inconsistency with the vendor's recommendations regarding RHR pump minimum flow as **URI 50-271/97-201-06**.

- The licensee's modification of its operating instructions in response to IE Bulletin 88-04 did not adequately reflect the vendor's instructions regarding RHR pump minimum flow operation. Although the 350-gpm bypass capacity did not support RHR pump operation beyond the 30 seconds, the operating procedures contained no such restrictions. Instead, the licensee revised the operating and surveillance procedures to caution the operators to minimize pump operation in the minimum flow mode. During the inspection, the licensee revised operating procedures to reflect vendor recommendations on the RHR minimum flow requirements.

- Finally, the team was concerned with the fact that operator action was necessary within the first 30 minutes under certain accident scenarios to prevent possible damage to the RHR pumps. The team considered the operator intervention to overcome a design deficiency as a change to the RHR system design and a change to the LPCI mode of RHR operation as described in the FSAR (**URI 50-271/97-201-07**).

e. **RHR Pump Motor Starts - Procedure Precautions**

The team requested that the licensee provide the basis for the precaution in OP 2124, "Residual Heat Removal System," Rev 41, which allowed three RHR pump starts in 5 minutes, followed by a 20-minute run or a 45-minute shutdown for cooling. VY noted that the National Electrical Manufacturers Association (NEMA) MG-1 required that motors be capable of two starts in succession, with the motor initially at ambient temperature. GE Nuclear Energy services also provided a response (by letter dated June 5, 1997) which indicated that each RHR motor was capable of three starts from ambient, without adversely affecting the integrity of the motor, provided that the acceleration time was less than 5 seconds and the ambient temperature was less than 30°C (86°F). However, the licensee indicated that the maximum normal operating temperature for the RHR corner rooms was 109°F and the room temperature may reach 155°F during accidents. The team therefore considered the 86°F limitation on successive pump starts to be inconsistent with the normal and design temperatures for the RHR corner rooms.

Criterion III to 10 CFR Part 50, Appendix B, "Design Control," requires that licensees must correctly translate the design bases into specifications, drawings, procedures, and instructions. The team concluded, however, that the licensee's direction in the operating instructions (compared to the manufacturer's recommendations and limitations for RHR pump motor starts) failed to meet this requirement. This is identified as **URI 50-271/97-201-08**.

f. **Failure to Update FSAR**

During their internal service water operational performance inspection (SWOPI) in 1994, the licensee found that RHR heat exchanger performance was over-estimated because (1) tube plugging was not considered, (2) the fouling allowance was too low, and (3) the tube wall thickness was larger than assumed (0.049 in. versus 0.035 in.). The re-calculated capacity was 52.5 x 10^6 Btu/hr, as determined in Calculation VYC-1290, Rev. 0, dated August 1, 1994. However, the licensee failed to update FSAR Table 4.8.1, Figure 4.8-1, Figure 6.4-3 and Section 14.6.3.3.2, which still stated that the design heat transfer capability of the RHR heat exchanger is 57.5 x 10^6 Btu/hr.

The licensee failed to update the suppression pool post-LOCA temperature analyses presented in FSAR Section 14.6.3, which included an assumption that feedwater flow ceases at the beginning of a LOCA event. This assumption was considered conservative at the time that the analyses were performed (late 1960s to early 1970s). However, the licensee recently determined that it is more conservative to assume that the feedwater mass and energy addition would continue following the LOCA event. This new scenario would lead to an increase of about 10°F in the peak calculated post-LOCA suppression pool water temperature (from 166 to 176°F), assuming an initial pool temperature of 90°F. The licensee documented these results in Calculation VYC-1290, Rev. 2, dated August 8, 1996.

On March 26, 1996, the licensee notified the NRC that the plant was operating under a condition outside of its design bases. Specifically, the higher peak pool water temperature impacted the CSCS pump NPSH and equipment qualification. The licensee then prepared SE 96-008 and concluded that the increase in peak post-LOCA pool water temperature from 166 to 176°F did not constitute an unreviewed safety question.

The licensee predicated this conclusion on administratively limiting the maximum normal pool temperature to 90°F (revised to 87°F in May 1997) or less, even though the TS allowed 100°F. In addition, the licensee included a summary of SE 96-008 in the VY Cycle 18 Operating Report (dated May 2, 1997), which was submitted in accordance with 10 CFR 50.59(b)(2). However, contrary to the requirements of 10 CFR 50.71(e), the licensee had not updated the FSAR to reflect the results of this safety evaluation in their VY Cycle 18 Operating Report.

The licensee's failure to update the FSAR to reflect changes in RHR heat exchanger performance and suppression pool post-LOCA temperature analyses is contrary to the requirements of 10 CFR 50.71(e). This item is designated as **URI 50-271/97-201-09**.

g. **Torus Cooling /LCO Management**

The licensee identified a single failure vulnerability when the RHR system was aligned in the torus cooling mode and wrote ER 97-473 to document this concern. For certain LOCA events and single-failure considerations, realignment of valves for torus cooling would not be possible (because of a failure of the power supply) and would result in one LPCI pump flowing out the break area, and the second LPCI pump in torus cooling alignment. This condition would result in less flow than the minimum licensing basis of one CS pump, and one LPCI pump injecting into the intact recirculation loop to mitigate the consequences of an accident as described in the FSAR. The licensee stated that the LPCI system need not be declared inoperable because VY's licensing basis regarding surveillance testing did not require entering a limiting condition for operation (LCO) to perform testing. In addition, VY considered operation of the RHR system in the torus cooling mode to be an extension of HPCI and reactor core isolation cooling (RCIC) surveillance testing.

The team concluded that the VY practices of not entering TS LCO conditions when equipment was rendered inoperable for TS surveillance was not consistent with the NRC's operability guidance, as stated in Generic Letter (GL) 91-18. Specifically, Enclosure 2 to GL 91-18 provided technical guidance for operability determinations. Paragraph 6.4 of Enclosure 2 stated that if a TS surveillance required that safety equipment be removed from service and rendered incapable of performing its safety function, the equipment was inoperable. The GL further stated that the LCO action statement shall be entered unless the TS explicitly directed otherwise. The team considered the inability of the LPCI system to withstand a single failure while in the torus cooling mode to render the system incapable of performing its design safety function and, therefore, the licensee should limit the time the LPCI system is in the torus cooling mode.

The licensee did not have any licensing documentation to support the NRC's acceptance of the VY position that LCO entry to perform testing was not required. The licensee indicated that this was a matter of practice since initial operation, and no formal documentation of NRC approval was available. During the exit meeting on July 1, 1997, the licensee informed the team that they intended to enter an LCO whenever the RHR system was aligned in the torus cooling mode. The team identified this issue as **URI 50-271/97-201-10**.

This issue was previously identified in the NRC's Region I Team Inspection Report No. 50-271/93-80, dated September 7, 1993. VY's response, dated November 12, 1993, indicated that it had incorporated formal self-assessment of TS surveillance requirements to improve management controls into the Improved Technical Specifications (ITS) program, which is currently scheduled for submittal in the fourth quarter of 1998. The team identified the issue regarding the timeliness of followup commitments as **URI 50-271/97-201-11**.

E1.1.2.3 **Conclusions**

The mechanical design of the LPCI system was generally acceptable, and the system was capable of performing its safety function. The LPCI operating mode of the RHR system was capable of performing its safety-related coolant injection function in the event of a LOCA assuming a loss of normal power and a single active failure. LOCA analyses performed to evaluate CSCS performance incorporated adequate margins for LPCI surveillance test flow measuring inaccuracies, addressed flow diversion through the RHR pump minimum flow lines, and considered limiting single active failure cases. The licensee's component safety and seismic classifications, and specified codes and standards were appropriate, and that the design pressures and temperatures specified for piping and components, and the overpressure protection features provided, were adequate. The two RHR loops were physically separated such that no single physical event would make both loops inoperable.

Nonetheless, the team identified several concerns as follows:

- past operation outside of the plant's design bases when suppression pool water temperature exceeded 90°F (50-271/97-201-01)
- inadequate technical basis with regard to the RHR pump minimum flow requirements (50-271/97-201-06)
- change to the LPCI mode of RHR operation as described in FSAR (50-271/97-201-07)
- failure to enter TS LCO conditions when equipment was rendered inoperable (not consistent with GL 91-18 guidance) (50-271/97-201-10)
- failure to take timely and/or complete corrective actions to resolve the suppression pool water temperature issue (50-271/97-201-02)
- failure to issue an LER to report a condition outside of the plant's design basis (50-271/97-201-03)
- errors in the calculation of RHR pump NPSH margin (50-271/97-201-04)
- use of non-conservative LPCI flow rates in the LOCA analyses (50-271/97-201-05)
- failure to update the FSAR to reflect reduced RHR heat exchanger capacity and to incorporate revised containment analyses (50-271/97-201-09)

- inappropriate operating instructions regarding permissible RHR pump motor starts (50-271/97-201-08)
- lack of timeliness in the licensee's actions with regard to commitments for self-assessment of TS requirements (50-271/97-201-11)

E1.2 Residual Heat Removal Service Water

E1.2.1 System Description and Safety Function

The safety function of the RHRSW system is to provide sufficient cooling capacity for the RHR system during a DBA and to minimize the probability of a release of radioactive contaminants to the environment. The RHRSW system consists of four RHRSW pumps; two RHR heat exchangers; and the necessary piping, valves, and instruments. The system is Safety Class 3, with a Class I seismic design. Components and equipment are powered from the emergency buses, such that power is available during a loss of offsite power. The two RHRSW loops are redundant and physically separated, and each loop is capable of providing 100% of the cooling capacity required for safe shutdown. Isolation valves automatically close on loss of service water header pressure to isolate all non-essential equipment. In addition, the pump spaces are provided with safety-related room coolers (RRUs 7 & 8), which remove heat to avoid excessive temperatures in the RHR rooms.

E1.2.2 Mechanical

E1.2.2.1 Scope of Review

The mechanical design review of the RHRSW system included system walkdowns and discussions with system and design engineers as well as reviews of the plant's design and licensing documentation. The team reviewed applicable portions of the FSAR and TSs, as well as flow diagrams, physical drawings, vendor drawings, equipment specifications, a draft DBD, calculations, operating and surveillance procedures, and ERs. The team reviewed the appropriateness of the design, bounding conditions, validity of assumptions, design inputs, vulnerability of system components, overpressure protection, and adequacy of tests and surveillances.

E1.2.2.2 Findings

a. **RRUs 7&8 Test Measurement Inaccuracies**

The licensee had used the differential pressure (delta-P) method in Calculation VYC-1329, "RRU 7 & 8 Performance Assessment (Clean & Plugged)," Rev. 1, to determine the thermal performance of the two safety related unit coolers. This analysis used the relationship between the pressure drop across the heat exchanger and its heat removal capacity to determine the rate of fouling for the heat exchangers. Calculation VYC-1329 assumed that the increase in pressure drop was the result of fouled heat exchanger tubes.

The team found several problems with the test results. First, the team could not draw a coherent regression line through the test data points. Additionally, the test results indicated that the pressure drop across RRU 7 had decreased some 17 months after the heat exchanger was cleaned. This indicated improved thermal performance. Further, the measured pressure drop across the heat exchanger (10 psid) after it had been cleaned was much higher than what was calculated (2.5 psid) for a fouled cooler. The licensee attributed 3.5 psid of this 7.5 psid to instrument location and the remaining 4 psid to instrument inaccuracies. The tea n also determined that the results from Calculation VYC-1329 were not used as inputs to other safety-related calculations. The licensee informed the team that more accurate instruments were installed in February 1995, and future test measurements should be more consistent and more accurate.

Criterion XI in Appendix B to 10 CFR Part 50 requires that "...provisions for assuring that all prerequisites for the given test have been met, that adequate test instrumentation is available and used, ..." The team concluded that the test data obtained was indicative of a failure to meet this requirement. **URI 50-271/97-201-12.**

b. **Incorrect Assumption in the Calculation Methodology for RRU 7 and 8**

The licensee failed to update the heat exchanger fouling assumption used in Calculation VYC-1329, even though their inspection of the heat exchanger indicated that the assumption was incorrect. Calculation VYC-1329 assumed that gross silting would be the cause of increased differential pressure across RRUs 7 and 8. However, the licensee's inspection of the heat exchanger tubes (April 1995) found no evidence of silt fouling. The team concluded that the fouling of the heat exchangers resulted from other fouling mechanisms such as slime. After discussions with the licensee, it appeared that this discrepancy had a negligible effect, but the licensee issued ER-97-0634 to address this issue.

Criterion III in Appendix B to 10 CFR Part 50 states that the design control measures shall provide for verifying or checking the adequacy of design by the performance of a suitable testing program. Calculation VYC-1329 used an assumption which seemed reasonable when made; however, it was found that the initial assumption was incorrect during subsequent inspection of the heat exchangers. Nonetheless, the licensee did not revise their assumptions when the calculation was revised **(URI 50-271/97-201-13)**.

c. **Downgrade of RRUs 5 and 6**

The licensee had changed the safety classification of RRUs 5 and 6 from safety-grade to non safety-grade without performing a safety evaluation. Paragraph 10.7.6 of the FSAR stated that "the pump spaces are provided with space coolers (RRUs 5, 6, 7, and 8) fed from the Station service water system (SWS) to prevent overheating of the motors ..." Discussion with the licensee indicated that the safety evaluation was not performed because the engineer who had reviewed this change incorrectly determined that no safety evaluation was needed. After reviewing the licensee's procedure AP 6002, "Preparing 50.59 Evaluations and FSAR Changes," Rev. 5, the team determined that questions 2, 8, and 20 associated with the screening evaluation should have required the performance of a safety evaluation.

The licensee performed the screening evaluation during the inspection and agreed with the team that a safety evaluation should have been performed. The team concluded that the downgrading of RRUs 5 and 6 without a safety evaluation constituted a weakness in the safety evaluation screening process and identified this issue as **URI 50-271/97-201-14**.

d. **Oversight of the Safety Evaluation Process by the Plant Operational Review Committee (PORC)**

The team noted that the PORC had inappropriately approved the downgrading of RRUs 5 and 6 from safety to non safety grade without a safety evaluation. The licensee informed the team that performance weaknesses associated with the PORC had already been identified and addressed by Region I inspectors. In the licensee's letter NVY 94-89, dated September 2, 1994, VY notified the NRC that it was upgrading the process used for PORC evaluation of plant changes, and the upgrade process would be completed as of December 1994. The NRC responded in letter NVY 94-164, dated September 26, 1994, stating that the proposed corrective actions and preventive measures were adequate. The team noted that PORC's approval regarding the downgrade of RRU 5 and 6 took place before the licensee made improvements to the PORC review process.

e. **Deletion of RRUs 5 and 6 from the GL 89-13 program**

In a response to the NRC regarding GL 89-13, the licensee committed that safety-related RRUs 5 and 6 would be monitored and analyzed in accordance with the delta-P method specified in Section 8 of EPRI NP-7552 (paragraph d.1 in Attachment A to BVY 90-007, dated January 22, 1990). However, when the licensee removed RRUs 5 and 6 from the GL 89-13 program, they did not notify the NRC that these coolers were no longer covered by their monitoring program.

The team considered the removal of RRU 5 and 6 from the GL 89-13 program constituted a change from VY's licensing commitments and the licensee should have notified the NRC. The team identified this issue as **IFI 50-271/97-201-15**.

f. **Performance Testing of RHR Heat Exchangers**

The team found that calibration and other problems existed with regard to the instruments used to measure RHR heat exchanger performance. As part of the licensee's GL 89-13 program, the licensee performed a series of tests and some test results indicated as much as 46 percent discrepancy between the measured energy removed from the RHR system and the energy added to the service water system. Accuracy of more recent tests improved because of the licensee used more accurate instrumentation.

As a result of the inspection, the licensee reviewed calibration records of the instruments used, analyzed the data, and issued three ERs as follows:

(1) ER-97-0667, dated June 5, 1997, documented the fact that flow measuring instruments recorded more than actual flow.

(2) ER-97-0630, dated May 29, 1997, documented a condition in which the flow instruments exhibited inaccuracies as high as 12.35%, contrary to the value of 10% assumed in the analysis.

(3) ER-97-0602, dated May 23, 1997, documented the team's finding that the instrument computer input points used in the tests were uncalibrated. Specifically, these were the Emergency Response Facility Instrumentation System (ERFIS) points, which were used to record the service water supply temperature (F060), RHR inlet temperature (M062, M064), RHR outlet temperature (W098, W099), RHR flow (P001, P002), RHRSW flow (P05, P006), and RHRSW outlet temperature (TE 10-94A,B).

On the basis of the team's concerns regarding the heat exchanger test results, the licensee analyzed the impact of the instrument inaccuracies and documented their result in BMO No. 97-27. The BMO made a few recommendations, one of which was to "impose and maintain an administrative limit to restrict plant operation to river temperatures of 80°F or below." The river design temperature is 85°F.

Criterion XII in Appendix B to 10 CFR Part 50 requires that "Measures shall be established to assure that tool gages, instruments . . . are properly controlled, calibrated, and adjusted at specified periods to maintain accuracy within necessary limits." The team concluded that the test data obtained was indicative of a failure to meet this requirement. **URI 50-271/97-201-16**.

g. **Failure to Inspect RHR Heat Exchanger 1B (GL 89-13 Commitment)**

The licensee failed to test RHR heat exchanger 1B during the refueling outage in September 1996. In Attachment A to BVY 90-007 (from VY to NRC), the licensee stated that the RHR heat exchangers "will be tested by measuring their heat transfer capability . . . " and that both heat exchangers were tested once and will be tested during the next two refuel outages. In addition, the licensee stated that "a testing frequency will be determined to provide assurance that the design heat removal capability of these heat exchangers is maintained."

The team considered this a deviation from the licensing commitment to determine a testing frequency to provide assurance that the design heat removal capability of these heat exchangers was maintained. **URI 50-271/97-201-17**.

h. **Common-Mode Failure of Non Safety Regulators Affecting Safety-Related Diesel Generators**

The team found that the service water flow control valve for the plant emergency diesel generator (EDG) was susceptible to common-mode failure from its associated non safety-related pressure regulator. The failure of the flow control valve could cause a loss of all service water to the EDGs. This failure mechanism affected both trains of EDGs.

Service water to the EDGs was supplied through flow control valve FCV-104-28A. FCV-104-28A was a normally closed valve with a fail open setting, and the solenoid valve FSO-104-28A supplied air to operate FCV-104-28A. Because the air supplied to the solenoid valve was from a

nonsafety-related pressure regulator, a failure of the pressure regulator could result in the malfunction of the solenoid valve, which could prevent FCV-104-28A from opening. Additionally, since the non safety-related pressure control valve supplied air to the solenoid valves for both trains of EDGs, the failure of a single non safety-related pressure regulator could potentially disable both trains of EDGs.

Furthermore, the team noted a similar situation with the flow control valve in that a non safety-related regulator also supplied air to the valve positioner and flow controller FC-104-28A. Therefore, a failure of this non-safety pressure regulator could also cause closing of flow control valve FCV-104-28A. The team concluded that failure of either the flow control valve FCV-104-28A or flow controller FC-104-28A would cause the EDGs to become inoperable because of loss of service water.

The licensee initiated ER-97-0512, dated May 9, 1997, and a preliminary BMO evaluation. In addition, the licensee revised BMO-96-03 to analyze the condition. As a result, the licensee performed a commercial dedication on new air pressure regulators and installed them during the inspection.

Criterion III in Appendix B to 10 CFR Part 50 states that "Measures shall also be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components." Contrary to that requirement, failure of non safety-related pressure regulators may have prevented the operation of safety-related EDGs. **URI 50-271/97-201-18**.

i. **Service Water Intake Bay Ambient Temperature Upon Loss of Ventilation**

The team identified a concern regarding the operability of the service water pumps resulting from loss of service water room fans (non safety-related). Such a loss would cause the room temperature to exceed the NEMA rating for the motor insulation during the summer months. The service water rooms were cooled by natural convection when fans were lost. This natural draft was created by opening a ceiling damper during the summer months.

Based on the team's concerns, the licensee issued a BMO to address this service water operability issue. The licensee concluded that. although the NEMA rating for the Class B insulation of the motors will be exceeded, service water pump motors were tested to significantly higher temperatures and that higher ambient room temperature would shorten the life of the motor, but would not cause immediate failure. The team had no further questions on this BMO.

The team was also concerned that there were no alarms available to warn the operators of high ambient temperature conditions in the service water pump rooms. However, the team's review of design and licensing documents revealed that VY was not required to have these alarms for the service water pump rooms. The only indication of high room temperature was from the pump motor winding temperature instrumentation which would be affected by the room temperature. The motor

winding temperature instrumentation was not safety-related instrumentation. VY's calculation VYC-1387, "Service Water Pump Room Analysis," Rev. 1, assumed that only two service water pumps would be running when non safety-related fans were unavailable.

j. **Operability of SWS/LCO Management**

The team was concerned by the licensee's lack of timeliness in revising their Technical Specifications (TS) after identifying a TS requirement that appeared to be non-conservative. Specifically, TS 3.5.D.3 allowed all four service water pumps to be inoperable for up to 7 days. The team expressed a concern that the plant operation could be allowed for 7 days without any service water pumps being operable. The licensee informed the team that they had identified this issue on February 24, 1997, and wrote an event report. The resolution to that ER initiated a revision to OP-2181, which read "When it is determined that both SW subsystems are inoperable, the reactor shall be in a cold shutdown condition within 24 hours, unless a subsystem is sooner made operable or a BMO is written and approved." Although the procedure effectively imposes an administrative LCO, the team was concerned with the licensee's schedule for revising their TS. The licensee's original intention was to include this change to their TS in the ITS submittal, which appeared to be several years away. At the end of the inspection, the licensee informed the team that changes to TS 3.5.D.3 would be made in September 1997.

Additionally, the team found that the basis for TS 3.5.D.3 conflicted with FSAR Section 10.8.2. Specifically, the FSAR stated that the alternate cooling system (backup service water system) was not classified as an engineering safeguard system and was not designed to accept the consequences of a design-basis LOCA. Also, it was not immune to a single failure. However, the basis for TS 3.5.D.3 stated that the alternate cooling water system provided an alternate heat sink to dissipate residual heat after a shutdown or accident. The team verified that the FSAR statement was correct and the basis for the TS was incorrect.

Not revising their TS was considered a licensee's failure to take prompt corrective action to address conditions adverse to quality (**URI 50-271/97-201-19**).

k. **Tornado Missile Protection**

The team identified a concern regarding the acceptability of the licensee's use of the probabilistic risk assessment (PRA) methods to address tornado missile protection for some safety-related equipment. Specifically, the licensee's use of PRA appeared to be inconsistent with the licensing basis for the plant.

Although VY's FSAR did not specifically state that components which affect safe shutdown of the plant were designed to be protected from tornado induced missiles, Section XII.2.1.3 of the Preliminary Design Assessment Report(PDAR) indicated that components which directly affect the ultimate safe shutdown of the plant are located either under the protection of reinforced concrete or underground. These components included the SWS and the standby diesel generator system. If protective barriers were not installed, the structures and components were suppose to be designed to

withstand the effects of the tornado, including tornado missile strikes. However, the team found that several components did not appear to have adequate protection from the effects of tornadoes. Specifically, these systems included the service water supply line to the circulating water and service water traveling screens, service water piping to the diesel generators outside the diesel generator rooms in the turbine building, fuel oil transfer lines routed on the exterior of the pump house and the diesel exhausts.

When similar issue with respect to tornado protection was raised in the past - the team identified similar issues regarding adequate equipment protection from tornadoes in VY's Service Water Operational Performance Inspection (SWOPI), conducted in 1994 and during the NRC Electrical Distribution System Functional Inspection (EDSFI) (Report No. 50-271/92-81) - VY stated that probability of tornado missile damage to systems such as the fuel oil transfer lines was small and that no further action was warranted at this time. VY committed to address their long term resolution of this issue in the Individual Plant External Event Examination (IPEEE).

The use of PRA methods to address tornado missiles hazards was identified as **URI 50-271/97-201-20**.

E1.2.2.3 **Conclusions**

The mechanical design of the RHRSW system was generally acceptable, and that the system was capable of performing its safety functions when administrative limits are imposed. The system appeared to have adequate flow, with no identified problems regarding NPSH, and the design pressures and temperatures specified for piping and components were adequate. In addition, the licensee's calculations and analyses were generally comprehensive and accurate.

Nonetheless, the team identified several concerns as follows:

- operation of safety-related equipment which was dependent on the functionality of non safety-related equipment (50-271/97-201-18)
- heat removal capability of the RHR heat exchangers and the RRUs (50-271/97-201-12 and 50-271/97-201-16)
- instrument calibration and accuracy, as well as documentation of test frequencies and equipment requiring testing (50-271/97-201-12 and 50-271/97-201-16)
- timely revisions to TS (50-271/97-201-19)
- design process (50-271/97-201-13and 50-271/97-201-14)
- the acceptability of the use of PRA methods to satisfy licensing commitments with regard to tornado missile protection (50-271/97-201-20).

E1.3 Electrical/Instrumentation and Controls

E1.3.1 System Description and Safety Function

The electrical systems required to operate equipment in the RHR system include the 4160-volt AC safety-related buses which receive power from either offsite sources, onsite generation, the Vernon hydro-electric plant, or the two onsite EDG sets. These 4160 volt AC buses provide power to the 480-volt AC safety-related buses which, in turn, provide power to 480-volt AC motor control centers (MCCs) which distribute power to 480-volt AC loads, 125-volt DC battery chargers, and 120-volt AC instrumentation power supplies. The large redundant RHR pumps and motors are powered from the redundant 4160-volt AC safety-related buses, and the redundant 125-volt DC buses provide power to operate circuit breakers, solenoids, some of the motor-operated valves (MOVs) and the control power for the EDGs.

The Class 1E 125-volt DC system consists of two separate and redundant safety-related buses (DC-1 and DC-2). A 60-cell lead acid, 2175-ampere-hour (AH) battery and a battery charger serve each bus. A spare battery charger could be connected to either bus and could charge either station battery (A-1 and B-1). An additional safety-related battery, AS-2, supplies power to emergency loads in the same separation group as battery B-1.

E1.3.2 Electrical

E1.3.2.1 Scope of Review

The electrical design review of the LPCI system included system walkdowns and discussions with cognizant system and plant design engineers as well as reviews of design and licensing documentation. The team reviewed applicable portions of the FSAR and TS; design documents including drawings for the 4160-volt AC safety-related buses, emergency diesel generator (EDG) units, circuit breakers, MCCs, electrical cables and 125-volt DC; electrical calculations; ERs and OERs.

The review included verifying the functional capability of the plant's electrical systems to provide adequate power to operate the RHR system (and the associated equipment) in the LPCI mode under the plant conditions that were most demanding on the electrical system. Specific areas covered included load studies, sizing criteria, separation criteria, electrical coordination, short circuit and fault current analysis, and 125-volt DC surveillance test data.

E1.3.2.2 Findings

a. Vernon 69-KV Switchyard Low Voltage

Calculation VYC-1512, "Station Blackout Voltage Drop and Short Circuit Study," Rev. 0, dated March 5, 1997, documented a condition in which with the RHR pump terminal voltage could degrade

to as low as 3100 volts AC (77.5% of the rated nameplate voltage) during pump starts. This condition would exist when the Vernon 69-KV switchyard was at its minimum voltage (64.5 KV) and there was maximum load on the 69-KV/13.2-KV transformer that feeds the town of Vernon. By contrast, the calculation assumed that 3200 volts AC (80% of the rated nameplate voltage) was required for pump start. The licensee therefore issued ER 97-0409 to document the potential that the RHR pump might fail to start at a voltage lower than what was assumed in the calculations. Additionally, the licensee completed BMO 97-17 to assess pump operability.

The operability assessment determined that the specific RHR pump motor and pump speed torque curves provided reasonable assurance that the RHR pump can start with a voltage as low as 2800-volts AC (70% of the nominal, rather than the 80% assumed). However, at the team's request, the licensee performed an evaluation concerning the time required to accelerate the pump to rated speed at the reduced voltage of 2800 volts AC. The team found that the motor overcurrent relay would trip the motor before the pump reaches full speed at the reduced voltage of 2800 volts AC. Given the evaluation and relay trip time, the licensee determined that a minimum terminal voltage of 75% was determined as necessary in order to ensure a successful pump start. VY imposed administrative operating limits for monitoring and maintaining greater than 3900 volts AC on the Vernon tie line to ensure that sufficient voltage margin is maintained.

The licensee agreed to revise calculation VYC-1512 to resolve the potential for low Vernon tie line voltages. The team identified this issue as **IFI 50-271/97-21**.

b. **Main Station Battery Service Test**

The team reviewed surveillance test data for the main station battery service test performed on September 14, 1996, in accordance with OP-4215, "Main Station Battery Performance/Service Test," Rev. 6. This review revealed that the licensee failed to follow OP-4215 which required that the licensee attach the printout of the test records, which showed individual cell voltage (ICV) and battery terminal voltage readings, to the procedure. Record retention requirements have existed since Rev. 0 of the procedure, which was originally issued on September 3, 1989.

This is a failure to maintain quality assurance (QA) records in accordance with Criterion XVII of Appendix B to 10 CFR Part 50. The team identified this issue as **URI 50-271/97-22**.

c. **Standby Battery Charger CAB Single Failure**

In preparation for the inspection, the licensee identified a condition in which the connection of a standby battery charger to the DC-2 bus could potentially result in loss of both DC divisions. The standby charger "CAB" could be manually connected to either DC-1 or DC-2 busses and is available to substitute for battery charger CA-1 or CB-1 in the event of a normal charger failure or a maintenance outage. Battery charger "CAB" was not normally connected and was fed from MCC 8B (a Division I power supply). If battery charger "CAB" was connected to the 125-volt DC-2 Bus,

(a Division II power source) a failure of the Division I AC power system (with charger "CAB" providing power to DC-2) would lead to a loss of both DC divisions and eventually to the loss of control of the Division II AC system if charger power could not be restored before the batteries were depleted.

VY TS 3.10 allowed continued operation, without restriction, if the standby charger "CAB" was connected to either DC-1 or DC-2. Moreover, FSAR 8.6.2 stated that no single failure shall cause the loss of DC supply from batteries of both systems. However, a single failure could cause both 125-Vdc buses to become degraded if charger "CAB" was connected to DC-2 since both DC-1 and DC-2 would be supplied by chargers that were fed from Division I MCCs. A single failure (loss of Bus 8) and consequential loss of both chargers would cause both main station batteries A1 and B1 to discharge, eventually leading to a loss of both DC-1 and DC-2.

The team considered this a deficiency in the plant's TS requirement. The licensee has issued ER97-0177 to evaluate this deficiency. The team considers this as **IFI 50-71/97-23**.

d. **Battery Sizing Calculations**

The team reviewed Calculation No. VYC-298, "Battery Sizing Calculation for Vermont Yankee 125-V Station Batteries A-1 and B-1; Capacity Verification for Battery Chargers BC-1-1A and BC-1-1B," Rev. 10, dated April 22, 1997. This review revealed that batteries A-1 and B-1 were made up of 60 cells, C & D type LC-31. For the worst-case condition, batteries A-1 and B-1 had a design capacity margin of approximately 28.6% and 21.1% respectively with 60 cells, and 18.6% and 16.7% with 59 cells. The chargers used with batteries A-1 and B-1 were rated at 150 amperes and the team verified these ratings and found them to be adequate to meet the loading requirements.

The team also reviewed Calculation No. VYC-730, "Sizing Calculation for 125-V dc Station Battery AS-2," Rev. 1, dated March 4, 1997. This review revealed that the AS-2 battery comprised 59 cells, of C & D Type KC-9. For the worst-case condition, the AS-2 battery had a design capacity margin of 54% with 59 cells, and 27% with 58 cells. The charger used with battery AS-2 was rated at 100 amperes and the team verified that this rating was adequate to meet the loading requirements.

E1.3.2.3 **Conclusions**

The team concluded that electrical design was adequate and operating within the design limits for components that perform the engineering safeguards functions of the RHR LPCI mode. The team had concerns with calculation VYC-1512 which did not accurately indicate the voltage limitation for starting the RHR pump (IFI 50-271/97-21); the licensee failure to retain required battery records (URI 50-271/97-22); and the possibility of loss of both DC divisions with the use of the standby battery charger (IFI 50-271/97-23).

E1.3.3 **Instrumentation and Controls (I&C)**

E1.3.3.1 **Scope of Review**

The team reviewed applicable sections of FSAR Chapters 1, 3, 5, 6, 7, 8, and 9; TS; DBDs; vendor documents; piping and instrument diagrams (P&IDs); logic diagrams; electrical wiring diagrams; control wiring diagrams; instrument installation drawings; calculations; ERs and EDCRs. In addition, the team conducted interviews, and performed walkdowns of features associated with the RHR system to ensure the ability of the system to meet FSAR commitments and TS limits. The review included inspecting instrument installations, setpoints, and AC and DC control power provisions, as well as alternative shutdown and station blackout (SBO) provisions. The team paid particular attention to modifications performed by the licensee to verify continued adherence to design bases and licensing requirements.

E1.3.3.2 **Findings**

a. **Use of the Vernon Tie as an Alternate AC (AAC) Source for Station Blackout**

As a result of lessons learned from the Maine Yankee Independent Safety Assessment, the NRC reviewed VY's use of a backfeed through the main transformer as a delayed access source of AC power and inquired about the use of the Vernon tie as a second delayed access source of AC power. As a result of this review, the NRC took exception to the use of the Vernon tie as an offsite source in response to loss-of-power events and as an alternate AC (AAC) source of power for the purpose of meeting SBO requirements. VY reviewed this matter (and documented its finding in BMO 97-03) and concluded that since the Vernon Tie was used to meet the requirements of a delayed access AC source of power it could not be used as an AAC source of power. Additionally, the licensee found that no analysis existed to demonstrate that the backfeed through the transformer could meet the timing requirements of a delayed access AC source of power.

At the end of the inspection, VY committed to modify the backfeed to be an acceptable delayed access source of AC power and intended to use the Vernon tie only as an AAC source of power. The licensee also intended to submit FSAR changes by September 30, 1997. Resolution of the use of the Vernon tie for SBO considerations is identified as **IFI 50-271/97-201-24**.

b. **ECCS Initiation Signal Cabling and Wiring Separation**

Based on the team's walkdown of the ECCS initiation signal circuits, the team questioned the adequacy of VY's electrical wiring separation criteria. The team was concerned with the cables from reactor pressure vessel (RPV) level transmitters LT-2-3-72A, B, C, and D in conduits labeled as SI and SIIX, which were terminated in the same terminal box with no provisions for separating the wires. Likewise, cables from conduits labeled as SII and SIX were terminated in another terminal box. According to the separation criteria, cables labeled SI, SII, SIX and SIIX, were to be mutually separated from each other. Additionally, the team observed that cables entering control room

cabinets 9-32 and 9-33 (ECCS auxiliary relaying cabinets) were bundled together inside the cabinet up to the terminal blocks regardless of their division assignment.

The licensee consulted with GE, the original provider of the auxiliary relay cabinets, to determine if GE had conducted an analysis of the observed condition. GE was able to direct the licensee's attention to the NEDO document 10139. This document presented the results of a GE single-failure analysis, and concluded that no single failure associated with the commingling of the subject cables and wires could result in the loss of safety function for both divisions.

The team also found that the control wiring associated with the breakers (3V4, 3V, and 4V) used to power the safety-related electrical buses from the Vernon tie breakers were not separated. Although the wiring to the 52a/b auxiliary contacts associated with the Vernon tie breakers could not be inspected directly, the licensee informed the team that the wiring was not separated.

The licensee performed an analysis and concluded that no possible fault could interfere with the safety functions of the breakers in question nor could the fault be transmitted to other safety systems. The licensee also indicated that the condition had been previously analyzed with identical results; however no record existed for the earlier analysis.

Although the licensee was eventually able to verify that the observed wiring configuration in the plant was acceptable, the team noted that the VY separation criteria did not clearly define the acceptability of wiring installations in common enclosures. In addition, no program requirement existed which required the licensee to document the analyses of deviations from the separation criteria. Also, the separation criteria did not define all of the classification labels for cable and wiring, and the application of the criteria to panel wiring was vague. The licensee concurred that VY needed to upgrade the separation criteria to address exemptions from separation requirements. The licensee's actions to improve their program requirements was identified as **IFI 50-271/97-201-25**.

c. <u>Instrument Uncertainty Calculation Methodology</u>

The team reviewed instrument uncertainty calculations for selected instrument loops for the RHR system, including initiation and permissive signal loops and indication and recording loops. The team noted that the calculations did not include any specific provisions to account for the instrument drift effects on the performance of the instrumentation. In 1997, the licensee began issuing drift analysis calculations for selected hardware lacking vendor drift data to address the lack of provisions for drift in the instrument loop uncertainty analyses. The licensee agreed that VY should revise the uncertainty calculations to reflect the allowance for drift factors. The licensee also indicated that the development of procedures and schedules for this effort was underway. The licensee's schedule and new program to address this effort are identified as **IFI 50-271/97-201-26**.

d. **LPCI/RHR System Flow Loop Uncertainty**

The team's review of Calculations VYC-453 and 479 revealed a significant uncertainty tolerance associated with the RHR/LPCI flow instrument. The large uncertainty tolerance stemmed from the +6.1 % and -5.6% of full instrument loop uncertainty associated with the flow loop. As a result, a flow rate of 3920 gpm was required (2700 gpm plus .061*(20000 gpm)) to ensure that the LPCI pumps would have an adequate continuous minimum flow rate of 2700 gpm. The licensee issued ER 97-0694 to address this concern. ER 97-0694 imposed a procedural limitation of 4000 gpm to ensure RHR pump operation above the vendor-recommended minimum flow value.

In addition, the team determined that the large uncertainty associated with the flow indication also affects the upper end of LPCI operation. The RHR heat exchanger placed a constraint on the maximum continuous flow allowable through the heat exchanger at 7000 gpm to avoid detrimental effects of vibration on the heat exchanger. Therefore, flow through the LPCI should not exceed 5880 gpm (7000 gpm - .056*(20000 gpm) to avoid the flow range in which there would be concerns for heat exchanger vibration.

The licensee's resolution regarding the operation of the LPCI pumps to meet its minimum flow requirement and to avoid passing excessive flow through the RHR heat exchanger is identified as **IFI 50-271/97-201-27**.

E1.3.3.3 **Conclusions**

The team concluded that the design and installation of the I&C aspects of the system were generally acceptable. The team noted that VY needed to resolve the acceptability of the use of the backfeed and the Vernon tie as delayed access and AAC sources of power (IFI 50-271/97-201-24). The team also found that exceptions to the separation criteria were not well documented or recorded, and the application of the separation criteria within panels was not well defined for both NSSS and BOP installations (IFI 50-271/97-201-25). Additionally, the team identified the licensee's resolution regarding operation of the LPCI pumps to meet its minimum flow requirement and to avoid passing excessive flow through the RHR heat exchanger as IFI 50-271/97-201-27. The team also concluded that the instrument uncertainty calculation methodology used at VY needs to address the effects of instrument drift (IFI 50-271/97-201-26).

E1.4 **FSAR Review**

E1.4.1 **Scope of Review**

The team reviewed the appropriate FSAR sections for the LPCI and RHRSW systems, as well as associated electrical and I&C sections of the FSAR to verify consistency between the FSAR descriptions and design documentation.

E1.4.2 **Findings**

The team identified the following FSAR discrepancies:

- FSAR Figures 4.8-1 and 6.4-3 (Rev. 13) did not agree with drawing 5920-725 (Rev. 9). For example, LPCI flows and RHR heat exchanger duty differ. The licensee initiated ER No. 97-0626 to address this discrepancy.

- The text of FSAR Section 6.4 cited references (e.g., References 6.4.a, 6.4.b, and 6.4.c) which were neither identified nor described in the FSAR. The licensee initiated ER No. 97-0580 to correct this discrepancy.

- FSAR section 6.3, "Summary Description - Core Standby Cooling Systems," indicated that the low-pressure CSCS started automatically following a reactor vessel low-low water level signal and time delay or low-pressure signal. This conflicted with the LPCI system operation and the description of initiation signals as identified in FSAR Sections 6.5.2.5, 7.4.3.5.2, and 7.4.3.5.4, which stated that the LPCI system did not start on a low-pressure signal. These sections indicated that LPCI initiated on three initiation signals, (1) RV low-low water level concurrent with low reactor pressure, (2) primary containment (drywell) high pressure, (3) sustained RV low-low water level. The licensee issued an event report to document this discrepancy.

- The electrical power to the service water strainers and instrumentation was non safety-related. FSAR Section 8.5 indicated that these strainers were safety related. The licensee issued an event report to document this issue and initiate an FSAR revision.

E1.4.3 **Conclusions**

The team identified several instances in which the licensee failed to update the FSAR to ensure that it contained the latest information, as required by 10 CFR 50.71(e). Although individual items were not significant, collectively, they appeared to indicate a licensee weakness in updating the FSAR (URI 50-271/97-201-28).

E1.5 **Design Control**

E1.5.1 **Scope of Review**

The team reviewed engineering and design documents (drawings, calculations, specifications, etc.) for both the LPCI and RHRSW systems as discussed in previous sections of this report. During these reviews, the team assessed the effectiveness of the licensee's design control process.

E1.5.2 **Findings**

The team identified several design document discrepancies and inconsistencies, as follows:

- The RHR system functional control diagram (Drawing No. 5920-27, Rev. 15) incorrectly stated in Note 6 that the motive power for the RHR system injection valves in both loops shall originate from a common bus, which was automatically connectable to two alternate emergency bus sources. LPCI system component power supplies were modified in EDCR 73-31, but the licensee had not modified note 6 to reflect these modifications. The licensee initiated ER No. 97-0601 to correct this discrepancy.

- Relief valves RV-10-210A, and B were provided to relieve pressure from the bonnets of the normally open RHR injection valves V10-25A, and B to prevent valve pressure locking. The setpoint of the relief valves was changed from 1050 psig to 1150 psig by Work Order 76-0920, dated July 7, 1976; however, the licensee never updated the related design documentation, including the RHR system P&ID (Drawing No. G-191172), the valve drawings (Drawing Nos. 5920-2615 and 5920-11934), and FSAR Figures 4.8-2 and 7.4-6 (RHR system P&ID) to incorporate the setpoint change. The inservice test (IST) database was also in error since it extracted relief valve information from the P&ID. The licensee identified this discrepancy in preparation for this design inspection, as documented in ER No. 97-0569.

- Drawing No. 5920-FS-1495 depicts flood protection modifications made to the RHR corner rooms. This drawing indicated that a check valve was to be installed in the corner room sump pump discharge piping; however, the radwaste system flow diagram (Drawing No. G-191177, Sheet 1) did not show this check valve, and Operations verified that the check valve was not installed. The licensee initiated ER No. 97-0661 to address this discrepancy.

- In response to a condition identified by the licensee (and reported to the NRC in March 1997), the licensee revised the RHR system operating procedure, OP 2124, to disallow the use of the condensate transfer system as an alternate RHR system keep-fill method; however, the procedure revision was incomplete. Item 15 in the Precautions section of OP 2124, Rev. 42, still refers to the use of the condensate transfer system for RHR system keep-fill. The licensee initiated a procedure change form (in accordance with AP0037) to correct this discrepancy.

- Engineering Instruction WE-103, "Engineering Calculations and Analyses," Rev. 15, dated October 14, 1994, section 4.1.4.2, stated that, when information from QA design records was required, the licensee must ensure that the appropriate (governing) documents were used and that such documents were the latest approved revision obtained from the appropriate source. Calculation VYC-1349, Rev. 1, issued on April 30, 1997, referenced drawing G-191372, sh.1, Rev. 41. However, engineering had approved Rev. 42 of the drawing G-191372 on December 20, 1996. The author of the calculation used a drawing from the aperture card file not knowing that the aperture cards were uncontrolled documents (for information only) and were not

frequently updated. Also, there was no sign posted on the aperture card file to that effect. These practices appear to conflict with Engineering Instruction WE-103. The licensee has issued an ER 97-0588 to address this concern.

- Calculation VYC-298, Rev. 10, issued on April 22, 1997, referenced various drawings as listed in Section 3.0.5 (a) through (l), which were superseded by a later revision before the licensee issued Calculation VYC-298, Rev. 10. Review of the latest revisions of the drawings indicated some dc load changes. The licensee has verified that there were no operability concerns and that the battery has adequate margin to support the load change. Again, these practices appear to conflict with Engineering Instruction WE-103. The licensee has issued ER 97-0665 to identify this concern.

- Calculation VYC-811, "125 Vdc System Short Circuit Current Study," Rev. 2, evaluated equipment capability during short circuit conditions. It provided review of 125-Vdc circuit breakers to determine if they were sized properly, to interrupt the maximum calculated short circuit current. It failed to include short circuit contributions from the MOV loads listed in calculation VYC-1296. The licensee's preliminary review of expected short circuit current contributions attributable to MOVs showed that total system short circuit current will increase, but will remain within the short circuit rating of the dc buses and breakers.

E1.5.3 **Conclusions**

The team identified several design document discrepancies and inconsistencies. Individually, they were not significant to safety and did not constitute operability concerns; however, collectively, they indicated a weaknesses in the design control process. The licensee will address these deficiencies in their Configuration Management Improvement Project (CMIP) and improve the calculation and drawing processes. The team identified this issue as URI 50-271/97-29.

APPENDIX A

LIST OF OPEN ITEMS

This report categorizes inspection findings as unresolved items (URIs) and inspection followup items (IFIs) in accordance with Chapter 610 of the "NRC Inspection Manual." A URI is a matter about which the Commission requires more information to determine whether the issue in question is acceptable or constitutes a deviation, nonconformance, or violation. The NRC may issue enforcement action resulting from its review of the identified URIs. By contrast, an IFI is a matter that requires further inspection because of a potential problem, because specific licensee or NRC action is pending, or because additional information is needed that was not available at the time of the inspection.

Item Number	Finding Type	Title/Related Regulation
50-271/97-201-01	URI	Suppression Pool Water Temperature - Past Operation Outside Design Bases (E1.1.2.2.a)
50-271/97-201-02	URI	Untimely Actions to Resolve Suppression Pool Water Temperature Issue - 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action (E1.1.2.2.a)
50-271/97-201-03	URI	Failure to Issue an LER - 10 CFR 50.73(a)(2)(ii)(B) (E1.1.2.2.a)
50-271/97-201-04	IFI	Clarification of RHR Pump NPSH Margins and Correction of Calculation Errors (E1.1.2.2.b)
50-271/97-201-05	URI	Non-Conservative LPCI Flow Values Used in LOCA Analyses - 10 CFR Part 50, Appendix B, Criterion III, "Design Control" (E1.1.2.2.c)
50-271/97-201-06	URI	Insufficient Technical Basis as Requested by IEB 88-04 for Existing Minimum Flow, (E1.1.2.2.d)
50-271/97-201-07	URI	Change to LPCI Mode of RHR Operation As Described in FSAR (E1.1.2.2.d)
50-271/97-201-08	URI	Inappropriate Operating Instructions Regarding RHR Pump Motor Starts, 10 CFR Part 50, Appendix B, Criterion III, "Design Control" (E1.1.2.2.e)

50-271/97-201-09	URI	FSAR Not Updated to Incorporate Reduced RHR Heat Exchanger Capacity - 10 CFR 50.71(e) (E1.1.2.2.f)
50-271/97-201-10	URI	Entry into TS LCO Conditions when Equipment is Rendered Inoperable - TS 3.5.A.2 and TS 3.5.A.3 (E1.1.2.2.g)
50-271/97-201-11	URI	Timeliness to Followup Self-assessment of TS Surveillance Requirements (E1.1.2.2.g)
50-271/97-201-12	URI	Measurement Inaccuracies Regarding Room Coolers (RRU) 7 and 8 - 10 CFR 50, Appendix B, Criterion XI, "Test Control"(E1.2.2.2.a)
50-271/97-201-13	URI	Incorrect Assumption in the Calculation Methodology for RRU 7 and 8, 10 CFR Part 50 Appendix B, Criterion III, "Design Control" (E1.2.2.2.b)
50-271/97-201-14	URI	Downgrading RRUs 5 and 6 Without a Safety Evaluation, 10 CFR 50.59, "Changes, Tests, and Experiments" (E1.2.2.2.c)
50-271/97-201-15	IFI	Deleting RRUs 5 and 6 from the GL 89-13 Program - GL 89-13 Commitment (E1.2.2.2.e)
50-271/97-201-16	URI	Analysis of RHR Heat Exchanger using Tests Measurements Collected and Recorded with Inaccurate or Uncalibrated Instruments, 10 CFR Part 50, Appendix B, Criterion XII, "Control of Measuring and Test Equipment" (E1.2.2.2.f)
50-271/97-201-17	URI	Failure to Inspect RHR Heat Exchanger 1B - GL 89-13 Commitment (E1.2.2.2.g)
50-271/97-201-18	URI	Common-Mode Failure of Non Safety-Regulators Affecting Safety-Related Diesel Generators, 10 CFR Part 50. Appendix B, Criterion III, "Design Control" (E1.2.2.2.h)
50-271/97-201-19	URI	Failure to Take Prompt Corrective Action to Revise TS Discrepancy (E1.2.2.2.j)
50-271/97-201-20	URI	Use of PRA to Address Tornado Missiles (E1.2.2.2.k)
50-271/97-201-21	IFI	Vernon 69-KV Switchyard Low Voltage (E1.3.3.2.a)

50-271/97-201-22	URI	Main Station Battery Service Test - 10 CFR Part 50, Appendix B, Criterion XVII, "QA Records" (E1.3.3.2.b)
50-271/97-201-23	IFI	Standby Battery Charger CAB Single Failure (E1.3.3.2.c)
50-271/97-201-24	IFI	Use of Offsite Vernon Tie as Station Blackout AAC Power Source and as Offsite Delayed Access Source of Power (E1.3.3.2.a)
50-271/97-201-25	IFI	Upgrade of Cable Separation Criteria (E1.3.3.2.b)
50-271/97-201-26	IFI	Lack of Provisions for Instrument Drift in Instrument Uncertainty Calculation Methodology (E1.3.3.3.d)
50-271/97-201-27	URI	Excessively High Uncertainty for RHR Flow Indication and Recording Loop (E1.3.3.3.e)
50-271/97-201-28	URI	FSAR Deficiencies and Errors (E1.4.3)
50-271/97-201-29	URI	Design Control Weakness (E1.5.3)

APPENDIX B

EXIT MEETING ATTENDEES

NAME	ORGANIZATION
Ross Barkhurst	President, CEO - VY
Jim Callaghan	Manager, Mechanical Engineering - YAEC
Jim Chapman	Director, Nuclear Engineering - YAEC
Russell Clark	Acting VP - YAEC
William Cook	Sr. Resident Inspector - NRC
Don Davis	CEO - YAEC
Robert Gallo	Branch Chief, NRR/DISP - NRC
Frank Helin	Superintendent, Technical Services - VY
Kahtan Jabbour	Project Manager, NRR - NRC
Richard January	Manager, I&C Engineering - YAEC
Andrew Kadak	President - YAEC
Edward Knutson	Resident Inspector - NRC
Edgar Lindamood	Manager, Division of Engineering - VY
David McElwee	Licensing Engineer, Safety and Regulatory Affairs - VY
David Mannai	Manager, Reactor Engineering - VY
Greg Maret	Plant Manager - VY
Stan Miller	Design Engineering - VY/YAEC
Mark Mills	Manager, Fluids Systems, YAEC
Don Norkin	Section Chief, NRR/DISP - NRC
Don Reed	Sr. Vice President - VY
William H. Ruland	Branch Chief, DRS/Region I - NRC
Bill Sherman	Nuclear Engineer - Dept. of Public Service (Vermont)
Tom Schimelpfenig	Manager, Financial Planning - VY
Stephen Schultz	Vice President - YAEC
Robert Sojka	Manger, Licensing - VY
Robert Wanczyk	Director, Safety and Regulatory Affairs - VY
Jim Wiggins	Director, DRS/Region I - NRC
Don Yasi	Manager, Nuclear Services - YAEC

Note: Individuals listed above attended the team exit at Bolton, Ma. on June 13, 1997 and/or attended the public exit on July 1, 1997 at Brattleboro, Vt.

APPENDIX C

LIST OF ACRONYMS

Abbreviation	Meaning
AAC	Alternate AC
AC	Alternating Current
ACS	Alternate Cooling System
ADS	Automatic Depressurization System
AH	Ampere Hour
BEP	Best Efficiency Point
BMO	Basis for Maintaining Operation
Btu	British Thermal Unit
BWROG	Boiling Water Reactor Owners Group
CFR	Code of Federal Regulations
CMIP	Configuration Management Improvement Program
CRD	Control Rod Drive
CS	Core Spray
CSCS	Core Standby Cooling Systems
CWD	Control Wiring Diagram
DBA	Design-Basis Accident
DBD	Design Basis Document
DI	Department Instruction
ECCS	Emergency Core Cooling System
EDCR	Engineering Design Change Request
EDG	Emergency Diesel Generator
EDSFI	Electrical Distribution System Functional Inspection
ER	Event Report
ERFIS	Emergency Response Facility Instrumentation System
FSAR	Final Safety Analysis Report
GE	General Electric Co.
GL	Generic Letter
gpm	gallons per minute
HPCI	High Pressure Coolant Injection
hr	hour
I&C	Instrumentation and Control
ICV	Individual Cell Voltage
IFI	Inspection Followup Item
IP	Inspection Plan (or Inspect. . Procedure)
IPEEE	Individual Plant External Event Examination
IR	Inspection Report
IST	Inservice Test
ITS	Improved Technical Specifications
kV	kilovolts
LCO	Limiting Condition for Operation
LNP	Loss of Normal Power
LOCA	Loss-of-Coolant Accident
LOOP	Loss of Offsite Power
LPCI	Low Pressure Coolant Injection
MCC	Motor Control Center
MOPD	Maximum Operating Pressure Differential
MOV	Motor-Operated Valve

NEMA	National Electrical Manufacturers Association
NNS	Non Nuclear Safety
NPSH	Net Positive Suction Head
NRC	US Nuclear Regulatory Commission
NRR	Nuclear Regulatory Regulation, Office of (NRC)
NSSS	Nuclear Steam Supply System
OER	Operating Experience Review
OSTI	Operational Safety Team Inspection
P&ID	Piping and Instrumentation Diagram
PAC	Potential Adverse Condition
PDCR	Plant Design Change Request
PORC	Plant Operational Review Committee
psid	Pounds per squre inch differential
psig	Pounds per squre inch gage
QA	Quality Assurance
RCIC	Reactor Core Isolation Cooling
RG	Regulatory Guide
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RPV	Reactor Pressure Vessel
RRU	Room Coolers
SBO	Station Blackout
SBPI	Sulzer Bingham Pumps Inc.
SO	Standing Order
SRV	Safety Relief Valve
SSC	System Structure or Component
SSFI	Safety System Functional Inspection
SSFP	Standby Spent Fuel Pool
SWEC	Stone & Webster Engineering Corporation
SWOPI	Service Water Operational Performance Inspection
SWS	Service Water system
TS	Technical Specification(s)
UPS	Uninterruptable Power Supply
URI	Unresolved Item
VY	Vermont Yankee Nuclear Power Station
VYNPC	Vermont Yankee Nuclear Power Corporation
YAEC	Yankee Atomic Energy Corportation