U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.	50-271
Licensee No.	DPR-28
Report No.	97-03
Licensee:	Vermont Yankee Nuclear Power Corporation
Facility:	Vermont Yankee Nuclear Power Station
Location:	Vernon, Vermont
Dates:	March 9 - April 19, 1997
Inspectors:	William A. Cook, Senior Resident Inspector Edward C. Knutson, Resident Inspector
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EXECUTIVE SUMMARY

Vermont Yankee Nuclear Power Station
NRC Inspection Report 50-271/97-03

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six week period of resident inspection.

Operations

The inspector determined that administrative controls were promptly implemented to preclude the alignment of a containment vent or purge pathway that could result in standby gas treatment system overpressurization. The licensee's final analysis and corrective actions are pending **(IFI 97-03-01)**.

The VY staff appropriately cancelled TS Interpretation No. 21, concerning allowances to perform control rod drive venting or control rod drive changeout after less than 24 hours in cold shutdown, upon inspector review and a determination that it may conflict with TS requirements. The inspector found no evidence that the most recent revision had ever been utilized.

Potentially inadequate processing of two event reports, as discussed in an earlier inspection report, was reviewed and found to be appropriate to the circumstances. The inspector concluded that proper operability and reportability reviews had been conducted in a reasonable and timely fashion. The inspector considered a pending revision to the licensee's event report process administrative procedure, which will provide more definitive guidance for the documentation of operability determinations, as a good procedural enhancement.

Failure to satisfy the 30-day reporting requirements of 10 CFR 50.73 on four separate instances in the past two years constitutes a violation of minor significance and is being treated as a Non-Cited Violation consistent with Section IV of the NRC Enforcement Policy. VY staff heightened sensitivity to the report timeliness issue has resulted in LER timeliness improvements.

Maintenance

Maintenance performed on the "A" emergency diesel generator (EDG) during a four day limiting condition for operations maintenance period was conducted in accordance with station work control processes and approved maintenance procedures. The EDG was properly restored to service following replacement of a flanged portion of the exhaust manifold which was found cracked.

The licensee's immediate response to a blown out test plug on the "B" EDG was prompt, and actions to verify adequate thread engagement on the remaining plugs and to perform a root cause determination for the failure were appropriate.

The licensee's actions in addressing and resolving a core spray (CS) system 4kv breaker problem were appropriate and timely, and the conduct of CS system testing by the VY staff was good.

Engineering

The VY staff continues to aggressively examine their plant design basis and address design inconsistencies in a timely and proper fashion. The interim operability assessments for the identified cable separation issues appear appropriate, but will be reviewed further by the NRC staff (**URI 97-03-02**). The VY staff's handling of the cable separation issues, with respect to reportability and entry into the BMO process, was appropriate.

VY staff follow-up of a design question involving maximum postulated flood levels identified a postulated flooding pathway, via unsealed underground electrical cable conduits, into the class 1E switchgear rooms. No immediate corrective actions were deemed necessary and the final analysis of this postulated event and inspector review were still pending at the conclusion of the inspection period **(IFI 97-03-03)**.

The VY staff identified that a commitment to the Atomic Energy Commission to make the Northeast and Southeast corner rooms' equipment hatches watertight had not been satisfied. The VY maintenance staff subsequently applied an approved caulking material to seal around the equipment hatch to floor seams. No discrepancies were observed with the licensee's resolution of this issue.

VY determined that the previously assumed mild environment in the safety related switchgear rooms may be compromised by a steam pathway via ductwork common to the turbine building and switchgear rooms. The inspector noted that the licensee's immediate operability assessment was not clearly documented with the Event Report, but that the Basis for Maintaining Operation (BMO) provided a clearly written and detailed basis for continued safe plant operation. The licensee's final analysis and corrective actions are pending **(IFI 97-03-04)**.

An engineering staff IPEEE review concluded that a fire system header piping break (non-seismically qualified piping) in the lower administration building could cross-flood under the West switchgear room door and potentially threaten safety related switchgear. Immediate actions taken by the VY staff included a procedure revision to establish operator-performed compensatory measures, and development of a Basis for Maintaining Operation. The licensee's final analysis and corrective actions are pending **(IFI 97-03-05)**.

During reexamination of the 1988 VY flooding report, the VY staff determined that a break in the 4-inch fire system piping located in the reactor building 252 ft. elevation (Northwest corner) has the potential to overflow the existing berms and curbs protecting the Northeast corner room residual heat removal (RHR) and core spray (CS) systems. Preliminary reviews by the licensee indicate that existing station procedures provide adequate guidance to isolate the postulated break prior to the RHR or CS systems being jeopardized, and that the reactor building compensatory fire watches will provided prompt notification of a flooding condition. The licensee's final analysis and corrective actions are pending **(IFI 97-03-06)**.

The licensee has proper design configuration control processing in place and has three noteworthy review programs (DBD, ITP and ISP) in place to ensure proper identification and resolution of existing design discrepancies.

The HVAC systems engineer's follow-up of an inspector identified non-safety related HVAC modification was thorough and timely.

Plant Support

The existing configuration of radiation monitors on the refueling floor and in the new fuel vault does not satisfy the requirements of 10 CFR 70.24, nor have periodic criticality accident drills been conducted. This problem has minimal safety consequences based upon the minimal safety consequences of mishandling new fuel on the refuel floor and based upon a previous NRC staff determination that these licensee activities relevant to 10 CFR 70.24 could be accomplished safely without such measures being in place. The NRC is currently reviewing this problem in light of its Enforcement Policy. Accordingly, this area is unresolved pending further NRC staff review **(URI 97-03-07)**. Nonetheless, recent licensee efforts to come into compliance with 10 CFR 70.24 have not been well focused.

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Summary of Plant Status

Vermont Yankee (VY) operated at 100 percent reactor power throughout this inspection period with the exception of power reductions to conduct a planned rod pattern exchange (March 11, 1997) and to conduct periodic surveillance testing.

The Regional Administrator, Hubert J. Miller, and members of NRC staff were on site March 11-12, 1997, to tour the facility, talk with VY management and staff, and conduct the public Systematic Assessment of Licensee Performance (SALP) management meeting on March 12, 1997, at the Town Hall in Vernon, VT.

During the week of March 17, 1997, a team of NRC inspectors observed the licensee's annual Emergency Preparedness Exercise conducted on March 19, 1997, involving participation by the local and state emergency response organizations. The NRC team inspection findings, observations, and conclusions were documented in inspection report No. 97-01, dated April 23, 1997. The Federal Emergency Management Agency (FEMA) also observed the exercise and conducted a debrief of their exercise observations during a public meeting held on March 24, 1997, at the Town Hall in Vernon, VT.

At the close of the inspection period, the VY staff was preparing to conduct a unit shutdown to repair the body-to-bonnet steam leak on main steam line drain outside containment isolation valve, 2-V77. Valve 2-V77 had been leaking steam since shortly after start-up from the 1996 refuel outage and attempted on-line repairs had been unsuccessful.

I. Operations

O1 Conduct of Operations[1]

O1.1 Potential Overpressurization of Standby Gas Treatment (SBGT) System (92700)

On March 25, 1997, VY notified the NRC (Event No. 32016) in accordance with 10 CFR 50.72, that the potential for overpressurizing the SBGT system filter train housings exists should a design basis LOCA occur during primary containment inerting or de-inerting operations. The VY staff identified this during the review of a plant status report for an event at another nuclear facility (LaSalle). The inspector determined that administrative controls were promptly implemented to preclude the alignment of a containment vent or purge pathway that could result in SBGT system overpressurization. The inspector will examine the licensee's final analysis of this issue and related corrective actions in a subsequent inspection period. Inspector follow item **(IFI 97-03-01)**.

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[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

O8 Miscellaneous Operations Issues

O8.1 (Closed) URI 96-200-01: Technical Specification (TS) Interpretation No. 21 Conflicts with TS Requirement

a. Background (71707)

As documented in inspection report 96-200, the inspectors identified that TS interpretation No. 21, dated March 16, 1995, appeared to conflict with the requirements of TS definition section 1.O.V, "Shutdown" and TS sections 3.12.F and 4.12.F, "Fuel Movement." Specifically, TS interpretation No. 21 provided a justification for allowing control rod drive maintenance within the first 24 hours after achieving the COLD SHUTDOWN condition by allowing the reactor mode switch to be placed in the REFUEL position after cold shutdown conditions had been established, but within the first 24 hours. In contrast, TS 4.12.F requires that the reactor has been in the cold shutdown condition for a minimum of 24 hours prior to any fuel handling or movement in the reactor core. TS 1.O.V. defines cold shutdown as when the reactor mode switch is in the shutdown mode position and reactor coolant temperature is equal to or less than 212 F. Therefore, TS interpretation 21 created the possibility that the requirements of TS 4.12.F may not be satisfied, in that the reactor mode switch could be placed in the refuel mode position at less than 24 hours after reaching cold shutdown, and not subsequently returned to the shutdown mode position prior to the start of fuel movement. As a consequence, the VY staff cancelled TS Interpretation No. 21 via a VP Operations to Plant Manager memorandum, dated November 15, 1996. The inspector conducted a follow-up review of this item to determine if the VY staff operated the facility in conflict with TS 3.12.F, 4.12.F, or section 1.O.V in the recent past.

b. Observations and Findings

The inspector re-examined the conduct of the planned unit shutdown for the Spring 1995 and the Fall 1996 refueling outages and the current operating procedure OP-0105, "Reactor Operations," dated October 10, 1996. The inspector confirmed that the operations staff appropriately positioned the reactor mode selector switch for the operating and shutdown plant conditions prescribed by OP-0105. In addition, the inspector verified that OP-0105, section 5, "Phase 5 - Reactor Power Decrease (from rated power to mode switch in shutdown)," step C.34, duplicates the requirements of TS 3.12.F and 4.12.F to maintain the reactor in cold shutdown for a minimum of 24 hours prior to any fuel handling or movement in the reactor core.

The inspector determined that OP-0105 does specify placement of the reactor mode selector switch in the REFUEL position (step C.13) following full insertion of all control rods. The inspector noted that step C.13 is preceded in section C, step C.6 by placement of the mode switch in START/HOT STANDBY. Placement of the mode switch in START/HOT STANDBY reduces the reactor protection system neutron monitoring high flux trip setpoints, among other things. At this point in the reactor shutdown sequence, the reactor pressure (corresponding to coolant saturation temperature) may be between 350 psig and 950 psig and continued plant cooldown is an option, dependent upon the

licensee's operational needs. The inspector determined that VY's TSs do not prohibit mode switch positioning to REFUEL during this phase of reactor shutdown operation and that the licensee's technical basis was well founded while the reactor vessel is greater than 212 degrees F. The technical basis is to minimize thermal cycles on the control rod stub tubes due to cold water injection caused by unnecessarily scramming fully inserted control rods with the mode selector switch positioned to SHUTDOWN.

In short, the inspector determined that under routine reactor shutdown operations the placement of the mode selector switch in REFUEL vice SHUTDOWN does not conflict with VY's TS. However, the inspector confirmed that it is the licensee's clear understanding that to comply with a postulated TS required shutdown per a limiting condition of operation action statement (i.e., TS 3.5.A.6, which states that if the requirements of TS 3.5.A cannot be met, an orderly shutdown of the reactor shall be initiated and the reactor shall be in a cold shutdown condition within 24 hours), the mode selector switch must be in the SHUTDOWN position within the specified time frame, regardless of the operational consideration delineated by OP-0105.

The inspector also researched the possible implementation of TS Interpretation No. 21 for the stated purpose of control rod drive venting or control rod drive changecut. Since the issuance of the most recent revision to TS Interpretation No. 21 (dated March 16, 1995) the interpretation had not been used (greater than two years and two refueling outages). This was verified by discussions with responsible plant staff and examination of the shift supervisor logs (official operating record) for 1995 and 1996.

c. Conclusion

The VY staff appropriately cancelled TS Interpretation No. 21 upon inspector review and a determination that it may conflict with TS requirements. In spite of its issuance (revision 2, dated March 16, 1995) the inspector found no evidence that it had been implemented since that date. This unresolved item is closed.

O8.2 (Closed) URI 96-200-02: Compliance with Instructional Guidance Involving Documented Operability Basis

a. Background and Inspection Scope (40500)

As documented in section O2.2 of inspection report 96-200, the VY staff had not routinely documented their operability decisions involving degraded or potentially degraded plant equipment. In addition, the inspection team noted that the current AP-0009, "Event Reports" guidance provides for department head (DH) initial screening of Event Reports (ERs). The team assessed that the DH screening created the potential for the shift supervisor not being promptly appraised of a condition which may impact safety system operability, if the DH's initial screening was improper or incorrect. The team reviewed two specific Event Reports (ERs) which appeared to demonstrate the above process vulnerability. The inspector conducted a followup review of these two ERs (Nos. 96-0149 and 96-0619) to determine if these events were improperly processed via AP-0009 and if operability and reportability determinations were incorrect or untimely.

b. Observations and Findings

Event Report No. 96-0149, was initiated on February 27, 1996, by the on-shift reactor engineer to identify the condition that the average power range monitor (APRM) gain adjustment factors were greater than 1.0 for APRMs "A","E", and "D". Upon identification, the control room staff (under the supervision of the shift supervisor) inserted a half scram on reactor protection system channel "A" until gain adjustments of the affected APRMs could be performed per operating procedure (OP)-4400. As documented in inspection report 96-200, the department head review section A.1. "immediate operability review" of ER 96-0149 was checked "no" vice "yes (immediately notify SS)." The inspector concluded this was an administrative oversight by the DH, because the shift supervisor was obviously cognizant of the APRM operability impact and directed the RPS channel "A" half scram insertion until the situation was corrected. In addition, the inspector determined that the shift supervisor had signed for having completed an initial reportability review (not reportable) as annotated in Part 3: "Reportability (SS/SE)" of ER No. 96-0149 by his signature and date.

Event Report No. 96-0619, was written on September 8, 1996, to document a motor-operated valve (MOV) limit switch problem identified while control room operators were placing the "D" residual heat removal (RHR) pump in service for shutdown cooling on September 7. The inspector determined from reconstruction of inspector field notes and discussion with operations staff that the problem occurred on the day shift of September 7, and was manifested by the failure of the "D" RHR pump to start because the pump suction valve (VIO-15D) open position limit switch did not satisfy the pump start interlock. Operators (under the direction of the shift supervisor) engaged the valve VIO-15D manual handwheel to fully open the valve and trip the limit switch, thereby satisfying the pump start logic. The SS subsequently had the VIO-15D motor-operated breaker protective tagged until the cause of the limit switch problem could be determined.

As captured in the ER 96-0619 event description, the design engineers determined that the limit switch (rotor #3) for pump interlock was set within the same tolerance as the valve travel limit switch (rotor #1). This condition resulted in the valve travel limit switch picking-up prior to the pump interlock. Motor operated valve limit switches should be set-up such that the logic input rotors are satisfied prior to valve travel rotors. The VY staff erred in the limit switch set-up for VIO-15D. Subsequent design engineering staff investigation identified other MOVs with the same specifications for the limit switch rotor #1 and #3 settings, but all were verified to have been set properly.

The inspector notes that ER 96-0619 was written the day following the event by the responsible MOV design engineer and the DH review was by the maintenance manager the subsequent day (September 9, 1996). In that VIO-15D is the shutdown cooling suction isolation valve to the "D" RHR pump, it does not serve a safety function with respect to emergency core cooling systems (ECCS). Therefore, the September 7, 1996 event, alone, was not reportable per 10 CFR 50.72 or 50.73. However, as annotated in ER 96-0619, the potential problem of several MOVs with improper limit switch rotor settings was much broader and the VY staff subsequently determined that this potential MOV problem was reportable (reference inspection report 96-09, section O1.3, ENS Event No. 31046, and LER No. 96-21).

c. Conclusions

Based upon the above discussion, the inspector concluded that the processing of ER 96-0619 and ER 96-0149 was appropriate to the circumstances, and that proper operability and reportability reviews were conducted in a reasonable and timely fashion. At the conclusion of the inspection period, the VY staff was processing a revision to AP-0009 which will provide more definitive guidance for the documentation of operability determinations. The inspector viewed this pending revision as a good procedural enhancement. This unresolved item **URI 96-200-02** is closed.

O8.3 (Closed) URI 96-200-03: Untimely Submittal of Licensee Event Reports (40500)

As documented in inspection report 96-200, section SA 2.2, the inspection team reviewed the 1995 and 1996 Licensee Event Reports (LERs) and identified four LERs which were submitted beyond the 10 CFR 50.73 30-day limit (two LERs in 1995 and two LERs in 1996). Follow-up discussions with the responsible VY staff determined that they were sensitive to this LER reporting timeliness issue and had generated an Event Report earlier to help focus on the problem and develop appropriate corrective actions. VY staff heightened sensitivity to the report timeliness issue and recognition that the issues requiring an LER need not be fully developed and documented in an LER within 30 days (supplemental reports are appropriate) have resulted in LER timeliness improvements since the team inspection. The failure to satisfy the 30-day reporting requirements of 10 CFR 50.73 on four separate instances in the past two years constitutes a violation of minor significance and is being treated as a Non-Cited Violation consistent with Section IV of the NRC Enforcement Policy. This unresolved item **URI 96-200-03** is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Observations

a. Inspection Scope (62707)

The inspectors observed portions of plant maintenance activities to verify that the correct parts and tools were utilized, the applicable industry code and technical specification requirements were satisfied, adequate measures were in place to ensure personnel safety and prevent damage to plant structures, systems, and components, and to ensure that equipment operability was verified upon completion of post maintenance testing. The inspector also reviewed the events surrounding the failure of an injector test port plug during surveillance testing of the "B" EDG on March 23, 1997.

b. Observations and Findings

"A" Emergency Diesel Generator Maintenance

The inspector observed the conduct of preventive maintenance on the "A" emergency diesel generator (EDG) during the week of March 24, 1997. The inspector noted that maintenance was being properly performed in accordance with Work Order No. 96-11792 and OP-5223, revision 16. The EDG was properly restored to service on March 28 following replacement of a flanged portion of the exhaust manifold which was found cracked.

"B" Emergency Diesel Generator Cylinder Plug Failure

In preparation for a planned four-day maintenance outage of the "A" EDG, surveillance testing of the "B" EDG was performed to first verify its operability. When the engine was started, a threaded test port plug in the number two cylinder injector blew out. This resulted in a jet of flame, several feet in length, being ejected from the port each time the cylinder fired. Personnel in the "B" EDG room immediately reported the condition to the control room and tripped the fuel racks, shutting down the engine. The flames had not impinged on anything, and thus there was no secondary fire as a result of the problem. The ejected plug did not cause personnel injury or damage to other equipment.

Each cylinder injector has a test port that is used to measure cylinder pressure for engine performance trending. When not in use, the test port is closed with a threaded plug. The apparent cause of failure in this case was insufficient thread engagement between the plug and the injector port. As corrective action, a new plug was installed, and all remaining plugs on the "B" EDG were verified to have adequate thread engagement. Surveillance testing of the "B" EDG resumed later the same day, and was completed without incident.

The inspector determined that this maintenance preventable failure of the "B" EDG did not result in exceeding the criteria (more than two failures in three years) for paragraph (a)(1) categorization per 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This failure was the first in three years to have occurred on the "B" EDG. At the conclusion of the inspection period, the licensee's final root cause determination for this event was still in progress. The inspector noted that all test port plugs were replaced on the "A" EDG during the LCO maintenance outage.

c. Conclusions

Maintenance on the "A" EDG was properly conducted. The VY staff's immediate response to the blown out test plug on the "B" EDG was prompt, and actions to verify adequate thread engagement on the remaining plugs and to perform a root cause determination for the failure were appropriate.

M1.2 Surveillance Observations

a. Inspection Scope (61726)

The inspectors observed portions of surveillance tests to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to LCOs, and correct post-test system restoration.

b. Observations, Findings, and Conclusions

The inspector observed the performance of core spray (CS) system surveillance testing conducted in accordance with OP 4123, on April 8, 1997. The inspector observed the pre-evolutionary briefing, which clearly discussed the expected conduct of the test and the planned replacement of the "A" CS pump 4kv breaker with a spare breaker after the completion of the "B" CS pump surveillance and prior to the "A" CS pump test. The inspector observed good communications and coordination of the surveillance testing and breaker work by the operations and maintenance staffs.

During the 4kv breaker replacement, the licensee identified that the closing spring on the "A" CS pump breaker did not discharge upon removal of the breaker from the cubicle. The inspector noted appropriate precautions being taken by the auxiliary operators, electricians, and the electrical foreman overseeing these work activities. The foreman promptly contacted the electrical maintenance engineer and the operators informed the shift supervisor of the breaker problem. The inspector witnesses good as-found measurement taking and troubleshooting, as well as, appropriate decision-making and coordination of work activities with the shift supervisor in the control room. Spare breaker adjustments were properly made in accordance with applicable maintenance control procedures before the breaker was installed in the cubicle, tested, and the "A" CS pump declared operable.

Subsequent investigation of the "A" CS pump breaker by the electrical maintenance staff concluded that the failure of the closing springs to discharge was attributable to a minor mechanical adjustment and that this problem did not adversely impact the breaker's safety functions. The inspector found the licensee's actions in addressing and resolving this 4kv breaker problem appropriate and timely and that the conduct of CS system testing by the VY staff was good.

III. Engineering

E1 Conduct of Engineering

E1.1 Electrical Cable Separation Review

a. Background and Inspection Scope (37551)

Following the completion of an update to the 10 CFR 50, Appendix R, Fire Hazards Analysis (FHA) and a revision to the Safe Shutdown Capability Analysis (SSCA), the licensee initiated a review of their 1985 Multiple High Impedance Fault Analysis. The

inspector determined that in revising the SSCA, the VY staff concluded that the SSCA revisions and associated plant modifications did not compromise the validity of the 1985 Multiple High Impedance Fault Analysis. However, the licensee initiated the review because the 1985 Analysis did not have the desired specificity or match the overall quality of the new SSCA and FHA. In conducting the upgrade of the 1985 fault analysis, the responsible engineers identified on March 27, 1997 that the lighting panel (LP)-1SR transformer feeder cable (C40232A) was routed through both SI and SII divisional electrical cable trays. This cable routing was in direct conflict with the VY cable separation criteria as specified in UFSAR, Section 8.4.6, "Cable Installation and Separation Criteria," and VY Specification No. VYS-27, "Separation criteria for reactor protection, engineered safety feature and auxiliary support systems, related electrical equipment and wiring." Specification No. VYS-27 establishes a coherent and definitive set of criteria to provide physical separation and electrical isolation of circuits and components so that the safety functions required during and following any design basis event can be accomplished. The inspector conducted a follow-up inspection to review this initiating event and the immediate actions taken by the VY staff to identify the extent of this cable separation concern and to assess the adequacy of the VY's preliminary operability determinations.

b. Observations and Findings

The inspector examined the immediate actions taken by the VY staff to address the LP-1SR transformer feeder cable and determined that the feeder breaker to the cable was opened and protective tagged to prevent energization and potential electrical fault propagation. Prompt action was also initiated to review other non-nuclear safety (NNS) related lighting panel feeder cables for similar improper routing. These actions and the initiation of the Basis for Maintaining Operation (BMO) process were documented in Event Report (ER) No. 97-303. The event was promptly reviewed by the control room staff and determined reportable per 10 CFR 50.72 (Event No. 32035) as a condition outside the plant's design basis.

The inspector was promptly notified by the VY staff of this condition and confirmed the immediate corrective actions taken. The de-energization of LP-1SR did not adversely impact continued plant operation and nullified any potential operability impact on safety related equipment. Subsequently on March 31, 1997, the review of potentially similar NNS lighting circuits identified the feeder cable to LP-NE/1A (C40245A) as routed through both SI and SII electrical cable trays. A field walkdown by the licensee of this condition confirmed the improper routing and ER No. 97-0317 was written.

Similar to the March 27, 1997 event, the control room staff made a 10 CFR 50.72 report (Event No. 32057) of this condition being outside the plant design basis. However, the inspector determined that, rather than de-energize LP-NE/1A, the VY staff concluded that the safety class electrical (SCE) circuit breaker associated with this lighting panel feeder cable provided adequate electrical fault protection, for an interim period, until the cable could be properly rerouted to satisfy the electrical separation requirements of UFSAR, Section 8.4.6. The inspector questioned the adequacy of the licensee's immediate operability assessment and made this issue unresolved (**URI 97-03-02**) pending further NRC staff review.

Concurrent with the March 31, 1997 event notification, the inspector learned that the VY staff had initiated a 100 percent review of all cable and conduit lists (CCLs) and cable tray isometrics to determine the full extent of this cable separation issue. The cable separation problem was preliminarily characterized as an original installation condition. The CCLs review took approximately five staff-weeks to complete, followed by a field walkdown to verify 70 identified problems. The inspector determined that the field walkdowns confirmed 62 electrical cable separation design specification non-conforming conditions (inclusive of the March 27 and 31 reportable events). Consequently, two additional 10 CFR 50.72 reports were made by the VY staff, (Event No. 32146, dated April 14 and Event No. 32163, dated April 16, 1997). The April 14 notification identified that the feeder cable (C1335AKSII) from electrical bus No. 9 to the uninterruptible power supply (UPS)-1A control panel (Division II) runs through an electrical pull box (B24DI) which is a Division I pull box that contains high pressure coolant injection system (Division I) cables. The cables are physically separated (not in the same cable bundle), but do not satisfy the UFSAR Section 8.4.6 cable separation criteria. The April 16 notification identified the remaining 59 cable separation issues which consist of 120 VAC instrumentation and control cables for NNS components which run through both Division I and Division II cable trays. The VY staff's immediate operability assessment for these two issues were similarly founded upon reliance on safety class electrical breakers protecting the potentially impacted safety related cabling. The adequacy of these operability assessments will also be reviewed by the NRC staff. **(URI 97-03-02)**

c. Conclusions

The VY staff continues to aggressively examine their plant design basis and address design inconsistencies in a timely and proper fashion. The interim operability assessments for the identified cable separation issues will be reviewed further by the NRC staff **(URI 97-03-02)**. The VY staff's handling of the cable separation issues, with respect to reportability and entry into the BMO process, was appropriate.

E7 Quality Assurance in Engineering Activities

The licensee's Design Basis Documentation (DBD) and Improved Technical Specifications (ITS) projects have the potential for identifying inconsistencies between the design, licensing, and operating bases of plant structures, systems, and components. Such inconsistencies will be documented in this section of the report and tracked to resolution as inspection follow items.

E7.1 Event Report 97-0197, Potential flooding of switchgear room via underground conduits during maximum postulated flood conditions (92700)

VY staff follow-up of a design question involving maximum postulated flood levels identified a postulated flooding pathway via unsealed underground electrical cable conduits. Flooding through these conduits could adversely impact the switchgear rooms as water would flow up through manways in the switchgear room floor and potentially jeopardize electrical bus work with a little as one inch of standing water. Upon review of this condition by the operations staff, a 10 CFR 50.72 notification (Event No. 31923) was made on March 10, 1997. No immediate corrective actions were deemed necessary and

the final analysis of this postulated event and inspector review were still pending at the conclusion of the inspection period. Inspector Follow Item **(IFI 97-03-03)**.

E7.2 Event Report 97-0223, Equipment hatch covers not sealed (92700)

During the review of the residual heat removal (RHR) system DBD, the VY staff identified that their June 1, 1973 response to a May 4, 1973 Atomic Energy Commission letter committed the plant to ensure the Northeast and Southeast corner rooms' equipment hatches would be made watertight. The purpose of the watertight seal is to prevent water intrusion to the lower elevations of the corner rooms from flooding on the reactor building 252 foot elevation. The hatches do not have a watertight sealing surface, so the VY maintenance staff used an approved caulking material and sealed around the equipment hatch to floor seams. This work was promptly completed and examined by the inspector the following day. No discrepancies were observed with the licensee's resolution of this issue. A 10 CFR 50.72 notification (Event No. 31925) was made on March 10, 1997, for this event.

E7.3 Event Report 97-0229, Turbine building high energy line break (HELB) potential adverse impact on switchgear rooms' environmental qualification (EQ) assumptions (92700)

Based upon further engineering staff review of the turbine building HELB issues previously reported (Event No. 31915) and documented in inspection report 97-02, Section O1.4 (also reference **IFI 97-02-03**), VY determined that the previously assumed mild environment in the safety related switchgear rooms may be compromised by a steam pathway via ductwork common to the turbine building and switchgear rooms. Discussions with the shift supervisor and operations manager following their 10 CFR 50.72 notification on March 10, 1997 (Event No. 31926) determined that VY's principle bases for concluding continued safe plant operations were: the ductwork pathway for steam to enter the switchgear rooms was long and tortuous; ductwork fire dampers may act to isolate steam flow (designed to isolate on a high temperature of 165 degrees F); and that following the HELB pressure relief via the blowout of the turbine building sheet metal siding, no appreciable driving head would be available to push steam to the switchgear rooms via the ductwork.

The inspector noted that this immediate operability assessment was not clearly documented with the Event Report, but that the Basis for Maintaining Operation (BMO) No. 97-08, dated April 11, 1997, provided a clearly written and detailed basis for continued safe plant operation. The inspector will examine the VY staff's detailed analysis and proposed corrective actions in a subsequent inspection period. Inspection Follow Item **(IFI 97-03-04)**.

E7.4 Individual Plant Examinations of External Events (IPEEE) Review Issues (37551)

The licensee's IPEEE review project has the potential for identifying inconsistencies between the plant design and its capability to cope with certain external events. The issues identified via this project will be documented in this section of the report and tracked to resolution as inspection follow items, as appropriate. The VY staff is currently

targeting completion of their IPEEE by the end of 1997.

Administration building fire system pipe break potential for adversely impacting the safety related electrical switchgear.

On March 13, 1997, the VY staff notified the NRC (Event No. 31949) in accordance with 10 CFR 50.72, that an engineering staff IPEEE review had concluded that a potential administration building fire system pipe break flood could place the unit outside its design basis. Specifically, a fire system header piping break (non-seismically qualified piping) of approximately 5,000 gpm in the lower administration building could cross-flood under the West switchgear room door and potentially threaten safety related electrical bus No. 8 with a standing water level of one to two inches. The water would pool in the west switchgear room because the existing floor drains are isolated for external flood protection compensatory measures (the switchgear rooms are approximately four feet below grade).

The inspector verified the immediate actions taken by the VY staff to address this potential internal flooding scenario. These actions included a revision to OP-2186, "Fire Suppression System," to direct operators to open the West switchgear room-to-turbine building double doors, if the administration building basement floor begins to flood. In addition, the Basis for Maintaining Operation (BMO) process was initiated to develop long term corrective actions. This issue will be examined in a future inspection period to assess the licensee's final analysis and corrective actions. Inspection Follow Item **(IFI 97-03-05)**.

Event Report 97-0359, Reactor building flooding due to postulated fire suppression system pipe break.

VY staff re-examination of the 1988 VY flooding report identified that the report erroneously concluded that a fire water system flooding rate of 7000 gallons per minute (gpm) could be successfully handled. New calculations show that a break in the 4-inch fire system piping located in the reactor building 252 ft. elevation (Northwest corner) has a projected flooding rate of approximately 5300 gpm (supplied by the newly installed 8-inch fire system piping). This amount of flow has the potential to overflow the existing berms and curbs protecting the Northeast corner room residual heat removal (RHR) and core spray (CS) systems. Additional calculations show that if the 8-inch fire system supply line is isolated, the original 4-inch supply line and postulated pipe break would result in an approximate 2600 gpm flooding rate. This amount of flooding was determined to not overflow the existing berms.

Preliminary reviews by the licensee indicate that existing station procedures provide adequate guidance to the operating staff to isolate a postulated fire system pipe break, prior to the RHR or CS systems being jeopardized due to water intrusion, and that the reactor building compensatory fire watches will provided prompt notification of a flooding condition. Review of the licensee's final analysis of this issue and long term actions, if needed, will be conducted in a subsequent inspection period. Inspection Follow Item **(IFI 97-03-06)**.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) URI 94-01-01: Design Configuration Control Concern (37551)

A. Background and Inspection Scope

As documented in inspection report 94-01, an apparent undocumented alteration of the service water pump room heating, ventilation, and air conditioning (HVAC) system contributed to the failure to start of the diesel driven fire pump (DDFP) due to cold engine conditions in January 1994. Specifically, air intake and exhaust dampers originally provided to control air flow to the room were removed, permitting unrestricted air flow. Cold ambient temperatures impacted the DDFP's starting capability because no engine block heaters were installed to maintain engine lubricating oil temperature. An unresolved item was initiated to assess licensee design configuration controls to ensure the HVAC system design control issue was not widespread.

b. Observations and Findings

In the past 22 months, the resident inspectors have monitored licensee design configuration controls and design change implementation practices and identified no programmatic design configuration control concerns. As reflected in recent inspection reports, the VY staff has initiated a design basis documentation (DBD) review effort, Improved Technical Specification (ITS) program, and Instrumentation Setpoint (ISP) review which have contributed to the identification of a number and variety of design related issues. Arguably, these identified design issues collectively could indicate that past design configuration controls were not as good as they could have been. However, each of these design issues has been assessed individually by the licensee staff and independently by the inspectors to ensure system operability and/or safety analyses are not significantly compromised. Where appropriate, corrective actions have been taken to ensure full compliance with regulations. Further, these issues have and will continue to be addressed per the NRC Enforcement Policy by the inspection staff.

During this inspection period the inspector conducted a follow-up of the turbine building high energy line break (HELB) design concern (reference inspection report 97-02, section O1.4, and Inspector Follow Item 97-02-03). The inspector identified during a walkdown of the turbine building and reactor building HVAC systems that a temporary ventilation system enclosure was not properly documented. The temporary enclosure is fabricated of plywood sheathing and lumber and channels the air flow between the turbine building HVAC fresh air plenum and the turbine building supply fans (TSF)-2A and 2B. Follow-up questions addressed by the VY HVAC systems engineer determined that the enclosure was installed per engineering design change request (EDCR) No. 82-34. The stated purpose of the enclosure was to reduce the fresh air heating caused by the air circulating in the room before being drawn into the supply fans. However, the VY systems engineer confirmed that the controlled duct work drawings were not revised via EDCR No. 82-34 (the HVAC flow diagram did not require revision). In addition, the referenced industry building standards for construction of the enclosure (endorsed by the applicable EBASCO construction specification) sheet metal called for ducting vice wood fabrication.

Accordingly, the systems engineer initiated an Event Report (No. 97-0269) on March 18, 1997 to ensure proper follow-up and resolution of these non-safety related HVAC system modification concerns.

c. Conclusion

The licensee has proper design configuration control processing in place and has three noteworthy review programs (DBD, ITP and ISP) in place to ensure proper identification and resolution of any old design discrepancies. The HVAC systems engineer follow-up of an inspector identified non-safety related HVAC modification was thorough and timely. This unresolved item is closed.

E8.2 (Closed) URI 96-09-07: Core Spray and Residual Heat Removal Systems Containment Isolation Valves Redesignated (37551)

By letters to the NRC dated October 15, 1996, the VY staff informed the NRC staff of their redesignation, for containment isolation purposes, of the core spray (CS) system inside containment injection check valves (CS-13A/B and CS-30 A/B), outside containment test isolation valves (CS-11 A/B), and the residual heat removal (RHR) systems inside containment injection check valves (RHR-46 A/B), and outside containment test isolation valves (RHR-25 A/B). The VY staff redesignated these containment isolation valves using the guidance of Regulatory Guide 1.141, ANSI N271-1976, and ANSI/ANS 56.2-1984. The Region I staff requested the NRC Office of Nuclear Reactor Regulations (NRR) to examine this containment isolation valve designation per 10 CFR 50.59 evaluation and assigned an unresolved item to this issue pending completion of NRR staff review.

By letter from the NRC to VY, dated March 3, 1997, the NRC staff completed their review and approval of re-designating the CS and RHR systems containment isolation valves. By a subsequent March 20, 1997 memorandum, the NRR staff forwarded their March 3, 1997 letter to the Region I staff for follow-up and closure of this unresolved item. Based upon the above, this unresolved item is closed.

IV. Plant Support

P2 Status of EP Facilities, Equipment, and Resources

P2.1 Criticality Accident Requirements

a. Inspection Scope (71750)

The inspector conducted a followup inspection of the licensee's compliance with 10 CFR 70.24, "Criticality accident requirements."

b. Observations and Findings

During the summer of 1996, the Office of Nuclear Reactor Regulation (NRR) requested information from the licensee regarding their compliance with the requirements of 10 CFR 70.24, "Criticality accident requirements." As a result of further review, the licensee

identified two areas of potential non-compliance with this regulation. Paragraph (a)(2) specifies that radiation monitoring devices used for detecting an accidental criticality, "...shall have a preset alarm point of not less than 5 millirems per hour..." However, the alarm setpoint for the new fuel vault radiation monitor was set at two millirems per hour. Secondly, paragraph (a)(3) states that, "The licensee shall maintain emergency procedures for each area...to ensure that all personnel withdraw to an area of safety upon the sounding of the alarm. These procedures must include the conduct of drills..." However, the licensee noted that no criticality accident drills had been performed. On August 2, 1996, the licensee initiated an event report (96-496) to address these issues.

During this inspection period, the inspector examined the licensee's compliance with the requirements of 10 CFR 70.24. The inspector noted that event report 96-496 remained open, and was informed that no action had been taken to resolve the identified discrepancies. The inspector reviewed operations procedure OP-3505, "Emergency Preparedness Exercises and Drills," revision 19, dated January 31, 1997, and verified that it did not specifically require the conduct of criticality accident drills. Other applicable procedures, such as OP-1400, "Fuel Receipt and Preliminary Handling," revision 22, dated July 2, 1996, and OP-1401, "New Fuel Inspection and Channelling," revision 21, dated July 2, 1996, likewise contained no requirements for the conduct of drills.

During this inspection period, the licensee adjusted the setpoint of the new fuel vault radiation monitor to within the range specified by 10 CFR 70.24. The licensee also indicated that the next revision of refueling procedures would include, as a prerequisite for new fuel movement, positioning a portable alarming radiation monitor (ARM) in the fuel handling area. In addition to these actions to comply with 10 CFR 70.24, the licensee indicated that they plan to apply for an exemption from this requirement, as allowed by 10 CFR 70.24(d). The licensee indicated that they had such an exemption as part of their construction permit, but that (apparently, by oversight) it had not been carried over into their operating license. The inspector verified that the licensee's special nuclear material license, SNM-1217, dated November 30, 1970, included this exemption, but this is no longer effective.

From discussions with plant personnel, the inspector was informed that the new fuel vault was not currently used for fuel storage, and had infrequently been used early in the plant's operating history. The current practice is to receive new fuel in shipping containers on the refueling floor, and to immediately store it in the spent fuel pool following offloading and receipt inspection. The inspector observed this to be the case during preparations for the 1996 refueling outage. Accordingly, the new fuel vault radiation monitor currently provides no practical value for detecting an inadvertent criticality because it is located in the new fuel vault inside a ventilation duct and shielded from the refuel floor by 18-inch thick concrete flooring. Since the only licensee activities that remotely fall under the requirements of 10 CFR 70.24 are offloading, inspection, and transport of new fuel into the spent fuel pool, the inspector considered the licensee's action to adjust the alarm setpoint of the new fuel vault radiation monitor as inconsequential to complying with 10 CFR 70.24.

c. Conclusions

The existing configuration of radiation monitors on the refueling floor and in the new fuel vault does not satisfy the requirements of 10 CFR 70.24, nor have periodic criticality accident drills been conducted. This problem has minimal safety consequences based upon the minimal safety consequences of mishandling new fuel on the refuel floor and based upon a previous NRC staff determination that these licensee activities relevant to 10 CFR 70.24 could be accomplished safely without such measures being in place. The NRC is currently reviewing this problem in light of its Enforcement Policy. Accordingly, this area is unresolved pending further NRC staff review **(URI 97-03-07)**. Nonetheless, recent licensee efforts to come into compliance with 10 CFR 70.24 have not been well focused.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors met with licensee representatives periodically throughout the inspection and following the conclusion of the inspection on May 6, 1997. At that time, the purpose and scope of the inspection were reviewed, and the preliminary findings were presented. The licensee acknowledged the preliminary inspection findings.

X2 Management Meeting Summary

On March 12, 1997, the Regional Administrator, Hubert J. Miller, and NRC staff met with Robert Young, Chairman of the Board, Ross Barkhurst, President and Chief Executor Officer, and the VY staff to discuss the March 5, 1997 Systematic Assessment of Licensee Performance (SALP) report in a public meeting held at the Vernon, VT Town Hall.

X3 Review of Updated Final Safety Analysis Report (UFSAR)

A recent discovery of a licensee operating its facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. Discrepancies that were noted were documented in the applicable section of the above report.

INSPECTION PROCEDURES USED

62707	Maintenance Observations
61726	Surveillance Observations
71750	Plant Support Activities
71707	Plant Operations
37551	On-Site Engineering
92700	On-Site Follow Up of Written Reports of Non-routine Events
40500	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems

ITEMS OPENED, CLOSED, AND DISCUSSED

OPEN

IFI 97-03-01	Potential Overpressurization of SBGT System
URI 97-03-02	Operability Assessments for the Identified Cable Separation
IFI 97-03-03	Potential Flooding of Switchgear Room via Underground Conduits
IFI 97-03-04	Turbine Building HELB Potential Adverse Impact on Switchgear Rooms EQ Assumptions
IFI 97-03-05	Administration Building Fire System Pipe Break Potential for Adversely Impacting the Safety Related Electrical Switchgear
IFI 97-03-06	Reactor Building Flooding Due to Postulated Fie Suppression System Pipe Break
URI 97-03-07	NRC Staff Review of Criticality Monitor Requirement (10FR 70.24)

CLOSED

URI 96-200-01	TS Interpretation No. 21 Conflicts with TS Requirement
URI 96-200-02	Compliance with Instructional Guidance Involving Documented Operability Basis
URI 96-200-03	Untimely Submittal of Licensee Event Reports
URI 94-01-01	Design Configuration Control Concern
URI 96-09-07	CS and RHR Systems Containment Isolation Valves Redesignated

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PARTIAL LIST OF PERSONS CONTACTED

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LIST OF ACRONYMS USED

VY	Vermont Yankee
NRR	Office of Nuclear Reactor Regulations
NRC	Nuclear Regulatory Commission
TS	Technical Specifications
EDG	Emergency Diesel Generator
LER	Licensee Event Report
RHR	Residual Heat Removal
HVAC	Heating, Ventilation, and Air Conditioning
DDFP	Diesel Driven Fire Pump
DBD	Design Basis Documentation
HELB	High Energy Line Break
EDCR	Engineering Design Change Request
URI	Unresolved Item
IFI	Inspector Follow Item
CS	Core Spray