U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.	50-271
Licensee No.	DPR-28
Report No.	97-04
Licensee:	Vermont Yankee Nuclear Power Corporation
Facility:	Vermont Yankee Nuclear Power Station
Location:	Vernon, Vermont
Dates:	April 20 - May 31, 1997
Inspectors:	William A. Cook, Senior Resident Inspector Edward C. Knutson, Resident Inspector Edward B. King, Physical Security Inspector George W. Morris, Reactor Engineer
Approved by:	Curtis J. Cowgill, III, Chief, Projects Branch 5 Division of Reactor Projects

EXECUTIVE SUMMARY

Vermont Yankee Nuclear Power Station
NRC Inspection Report 50-271/97-04

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection. In addition, it includes the results of physical security inspections by a physical security specialist and a regional reactor engineer.

Operations

A reactor scram occurred from 100 percent power due to personnel error while performing local power range monitor calibration, when two average power range monitor channels were inappropriately taken out of bypass while they were set to zero power. This failure to adhere to the calibration procedure was contrary to Technical Specification 6.5 and was a cited violation. Operator response to the transient was very good and, with some minor exceptions, plant response was normal. The licensee concluded that the root causes of this event were personnel errors in the areas of work practices and communications. Immediate and long-term corrective actions appeared to have adequately addressed the identified weaknesses. (Section 01.1)

Following completion of a nine-day maintenance outage, the subsequent plant startup and return to full power operation was well controlled. (Section 01.2)

A weekly surveillance revealed that oxygen concentration in the torus air space was greater than allowed by Technical Specification (TS). Prompt action was taken to verify this result and to reduce oxygen concentration to within TS limits. The condition was preliminarily determined to be due to inadequate nitrogen purging during containment inerting following plant startup. It also appears to have been the result of an unforeseen consequence of a recent change to eliminate the procedural option to inert the drywell and torus in parallel. Pending further inspector review, this issue was unresolved. (Section 01.3)

VY declared an unusual event (UE) based on receipt of a seismic monitor alarm. The cause of the alarm was later determined to have been a spurious indication from a single accelerometer, and the UE was terminated. Although, the event was correctly classified in accordance with the emergency procedures. (Section 01.4)

Several instances of weak operator performance were noted. The inspector was concerned that the number and nature of these instances was above normal. These observations and concern were discussed with and acknowledged by VY station management. (Section 04.1)

Maintenance

The licensee's decision to shut down for repair of main steam bypass valve, V2-77, was the result of a thorough review of the available repair options. Licensee preparations for this maintenance were thorough. The outage duration was extended primarily due to emergent maintenance that could not have been foreseen going into the outage. These issues were appropriately addressed prior to plant restart. (Section M2.1)

Post-scram review of individual control rod scram times revealed that one rod was significantly slower than the others. During subsequent scram time testing, the rod did not insert when scrammed. The cause was determined to be a defective scram solenoid pilot valve (SSPV) assembly. VY had replaced all SSPVs during the 1996 refueling outage, with units that are unique to VY in this application. The failed SSPV was returned to the vendor (Automatic Valve, or AVCO), who determined the cause to be binding of one of the two solenoid plungers. The binding was the result of wear products that were produced by cyclic impact (induced by the 60-cycle AC solenoid) of the plunger on the plunger backseat. The failed SSPV had been noted to be buzzing, along with nine other SSPVs, at the beginning of the operating cycle. As a result, VY inspected the remaining nine SSPVs that had been buzzing, and found evidence of wear on all of the associated plungers. No significant wear indications were observed on the plungers in solenoids that were not buzzing. VY concluded that solenoid buzzing could be used as a reliable indicator of incipient failure, and instituted periodic checks for noise. The root cause of this failure mechanism is currently under investigation. (Section M2.2)

Engineering

The emergency diesel generator (EDG) service water flow control valves are air-operated and were found to be supplied via non-nuclear safety related (NNS) pressure regulators in the instrument air system. A failure of the NNS pressure regulators could cause the flow control valves to fail in the closed position, which would isolate service water cooling flow through the EDG heat exchangers. The discovery of this system design vulnerability was made by the NRC Architect Engineering Team. A more detailed examination and summary of this finding will be documented in their report. (Section E1.2)

The VY Individual Plant Examination of External Events review identified that failure of several non-seismic piping systems could adversely impact safety related equipment. However, the licensee's immediate systems operability assessment concluded that the identified piping, although not seismic category I, was of sufficient design and strength to withstand design basis earthquake dynamic loading. (Section E7.2)

NRC reviewed the licensee's capability to meet station blackout backup electrical requirements. The licensee satisfies 10 CFR Part 50, Appendix A, GDC 17, "Electric Power Systems," and has committed to come into full compliance with 10 CFR 50.63 prior to start-up from the 1998 refuel outage. (Section E8.1)

A regional specialist visited the site and YNSD during this inspection period. The specialist reviewed the Vernon tie line cable testing and found it acceptable. The inspector also provided an update for Violation 50-271/96-09-06 corrective actions. One inspector followup item was opened as a result of those visits on the electrical circuit model used to support the evaluation of voltage dip during start of the fire pump. (Section E2)

Plant Support

The licensee maintained an effective security program. Management support was evident based on the effective implementation of the security program. Management controls for identifying, resolving, and preventing programmatic problems were effective, audits were thorough and in-depth, alarm station operators were knowledgeable of their duties and responsibilities, and security training was being performed in accordance with the NRC-approved training and qualification plan. The licensee's provisions for land vehicle control measures satisfy regulatory requirements and licensee commitments. Vehicles were being properly searched prior to permitting protected area access, as required in the Plan and applicable implementing procedures. (Section S)

TABLE OF CONTENTS

Report Details

Summary of Plant Status

At the beginning of the inspection period, Vermont Yankee (VY) was operating at 100 percent reactor power. On April 24, an inadvertent reactor scram occurred due to personnel error while performing a nuclear instrumentation surveillance. The plant utilized the unplanned shutdown for early commencement of a scheduled maintenance outage. Emergent work on the main transformer extended the original two day outage duration by approximately one week. A reactor startup was performed on May 7 and full power operation was achieved on May 9. The plant operated at 100 percent reactor power for the remainder of the inspection period with the exception of power reductions to conduct planned surveillance testing.

I. Operations

O1 Conduct of Operations[1]

O1.1 Reactor Scram Due To Personnel Error During Nuclear Instrument Surveillance Testing

a. Inspection Scope (71707)

The inspector observed operator response to an inadvertent reactor scram that occurred on April 24, and reviewed the licensee's investigation of the cause and actions to prevent recurrence.

b. Observations and Findings

On April 24 at 9:10 a.m., a reactor scram occurred from 100 percent power. The cause of the scram was personnel error while performing local power range monitor (LPRM) calibrations; specifically, two average power range monitor (APRM, an instrument that uses the output from several LPRMs to determine average power) channels were inappropriately taken out of bypass while they were set to zero power, which generated a reactor protection system (RPS) scram signal (APRM downscale). Plant response was as expected; all rods fully inserted, the main turbine tripped, and the turbine bypass valves operated to control reactor pressure. The rapid power reduction caused reactor water level to decrease to less than 127 inches (normal operating level is 160 inches), which produced primary containment isolation system (PCIS) isolations of group 2, (drywell drains and portions of the RHR system) group 3, (drywell ventilation), and group 5 (reactor water cleanup system). Feedwater control system response, along with level swell caused by reactor heating of the feedwater, subsequently caused reactor water level to exceed the high level trip setpoint for the reactor feedwater pumps. Feedwater pump restart was complicated by a failure of the condensate flow control valve automatic controller, but a pump was successfully started after the controller was placed in the manual mode. Reactor vessel level was then stabilized at its normal level. The reactor scram and PCIS actuation was reported to the NRC operations center (EN 32213) as required by 10 CFR 50.72.

---

[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.

The licensee had been planning to perform a controlled shutdown on April 29 for a two day mini-outage, primarily to repair a leaking main steam bypass valve. Rather than restarting the unit to operate for only four days, VY management decided to commence the scheduled outage early. Following single rod scram time testing and inspection of the drywell, plant cooldown was commenced on April 25, and cold shutdown conditions were established at 12:30 p.m. Outage activities are discussed in section M2.1 of this report.

The inspectors arrived in the control room several minutes after the scram. The inspectors observed that the operators were responding in accordance with the scram procedure, and that the response was well controlled. In particular, the inspectors noted that the shift supervisor demonstrated excellent command and control; while not becoming overly involved in specific operations, he demonstrated thorough comprehension of overall plant conditions through the conduct of several short briefings with the control room operators. These briefings reviewed the existing plant conditions, and addressed target conditions and near-term activities.

The licensee conducted an investigation to determine the root cause of the inadvertent reactor scram. The event occurred during the course of performing LPRM calibration and functional checks per Operating Procedure (OP)-4406, "LPRM Calibration and Functional Checks," Revision 13, dated October 18, 1996. This activity was being directed by a member of the reactor engineering staff (the reactor engineer), with actions being performed by operators and instrument and controls (I&C) technicians. At the beginning of the procedure, the two APRM channels (A and D) that were supplied by the LPRM channels to be calibrated, were placed in bypass (per step I.A.4.). These switches are on the main control board (MCB) and the action was performed by an operator. This action prevents test signals from being input to the RPS while the associated LPRMs are being calibrated. A subsequent procedural step (I.A.6.) performed by an I&C technician behind the MCB placed the APRM mode switches in the "Zero" position, but the restoration portion of the step which directed that these switches be placed back to the "Operate" position was missed. Later in the calibration, the procedure (step I.A.10.) called for a verification that APRM power was consistent with actual core thermal power, in preparation for taking the APRM channels out of bypass. However, the APRM channels both still indicated zero power, due to the earlier mispositioning of their mode switches. The reactor engineer knew that the next procedural step took the APRM channels out of bypass, and incorrectly concluded that this action would restore normal indication and allow the required comparison to be completed. The reactor engineer then directed the operator (a licensed reactor operator) to take the APRM channels out of bypass (per step I.A.11). The operator did not notice that the APRM channels indicated zero and restored both channels to operate in rapid succession (within about one second of one another). When each affected APRM channel was placed in operate, its zero indication generated a reactor trip signal (APRM downscale) on its respective RPS channel. Since the affected APRM channels each input to different RPS channels, this produced an actual reactor trip.

The failure of the VY operating staff to have adhered to OP-4406 steps I.A.6. and I.A.10., directly resulted in the reactor protection system actuation and reactor scram from 100 percent power at 9:10 AM on April 24, 1997. This is a violation of Technical Specification 6.5, "Plant Operating Procedures." **(VIO 97-04-01)**

The licensee concluded that the root causes were personnel errors in 1) work practices, and 2) communications. Specific work practice errors by the reactor engineer were failures to follow the procedure, in omission of the step to return the APRM mode switches to "Operate," and in not completing the procedural step to verify that APRM power was consistent with core thermal power prior to proceeding to the next step. The work practice error that was attributed to the reactor operator was failure to verify correct system response after returning the first APRM to service. Such a verification would have revealed the unexpected system response (one channel of the RPS tripped) and allowed it to be resolved before plant operation was affected. The verbal communication error was that the reactor engineer did not seek resolution of what he interpreted to be a procedural conflict (the APRM power comparison that could not be completed without performing the subsequent procedural step to take the APRMs out of bypass). In addition, the licensee identified procedure inadequacy (multiple actions required to be performed within a single procedural step) and lack of knowledge of APRM operations, as contributing causes.

As immediate corrective action, the licensee conducted training on lessons learned from this event with all licensed operators. In a meeting with all plant personnel, the expectation for procedural adherence and communication of emergent problems was stressed. Long term corrective action included review and upgrade of all reactor engineering procedures that have the potential to produce a half or full scram, and training for reactor engineering personnel on the neutron monitoring and reactor protection systems. These actions are anticipated to be completed prior to the end of 1997.

The inspector agreed that the cause of the scram was a combination of personnel errors. The inspector considered that a significant contributing factor was that the calibrations were being simultaneously performed on two APRM channels, with each APRM providing input to its respective RPS channel. While this is acceptable with respect to operability requirements, the operational consequences of an equipment malfunction or procedural error have the potential to be much more severe (as demonstrated by this event) than with a single channel calibration. The inspector noted that this aspect of the event, while not specifically identified as a cause in the licensee event report (LER 98-008, revision 0), will be examined as part of VY's corrective action.

c. Conclusions

The April 24 reactor scram occurred due to personnel error. The specific error was the failure to adhere to the surveillance test procedure OP-4406, "LPRM Calibration and Functional Check," steps I.A.6. and I.A.10., and is a violation of Technical Specifications. Operator response to the transient was very good and, with some minor exceptions, plant response was normal.

O1.2 Plant Startup and Return to Full Power Operation

a. Inspection Scope (71707)

During the period May 7-9, 1997, the inspectors observed portions of the plant startup and return to full power operation.

b. Observations, Findings, and Conclusions

Following completion of the outage to repair main steam bypass valve V2-77, plant startup was commenced on May 6. The reactor mode switch was placed in the STARTUP position at 9:34 p.m. Reactor startup was commenced at 12:57 a.m., May 7, and criticality was achieved at 2:38 a.m. Following reactor heatup and startup of the steam plant, the reactor mode switch was placed in the RUN position at 8:20 p.m. The main generator was synchronized to the grid at 10:08 a.m., May 8, and 100 percent power was achieved at 7:37 a.m., May 9.

The inspector observed portions of the plant startup from the control room. Operations were deliberate and well controlled. For example, when difficulty was encountered with initial rod movement on one rod (a condition that occasionally occurs due to the design of the control rod drive), actions were closely supervised by the shift supervisor, and strict procedural compliance was observed. Turbine generator startup and synchronization to the grid was also observed to have been performed deliberately and with close direction and oversight.

O1.3 (Open) Unresolved Item (97-04-02): high oxygen concentration in the torus air space during plant operations

a. Inspection Scope (71707)

On May 12, 1997, a weekly surveillance to measure oxygen concentration in the torus air space revealed that the concentration was greater than the four percent limit established by Technical Specification (TS) 3.7.A.7.

b. Observations and Findings

At 12:25 a.m., the torus air space oxygen concentration was measured to be 8.5 percent. This determination was made with one of the installed drywell hydrogen/oxygen monitors. A local sample, taken by a radiation protection (RP) technician using different monitoring equipment, indicated 7.5 percent oxygen. At 12:30 a.m., operators entered TS 3.7.A.8, which requires that an orderly shutdown be initiated immediately and that the reactor be in a cold shutdown condition within 24 hours, if TS 3.7.A.1 through A.7 cannot be satisfied.

Operators noted that similar indications had been observed during a weekly torus oxygen sample that was performed during November 1996, and that the cause had been an air leak on the containment air monitor (CAM); this event is discussed in inspection report 96-200. To eliminate this possible cause, the CAM was isolated.

The filter cover was examined and determined not to be leaking. In addition, torus oxygen concentration remained unchanged with the CAM isolated, further indicating that air leakage into the sample stream was not the cause of the problem. The RP technician then obtained a second grab sample from an alternate sample point in the containment atmosphere dilution system. At 4:00 a.m., this sample indicated 7.7 percent oxygen in the torus air space.

At 5:30 a.m., operators had commenced reducing reactor power as required by TS 3.7.A.8. In accordance with 10 CFR 50.72, the NRC was notified at 6:13 a.m. that the plant had commenced a TS required plant shutdown (EN 32314).

The torus air space had been inerted on May 8, in the normal course of the plant startup. The licensee suspected that the high oxygen concentration was the result of inadequate nitrogen purging during that operation, rather than being caused by air leakage into the torus air space. The apparent reason for the inadequate purge was that the procedure for inerting the drywell had been revised, since its previous use, to delete the option of inerting the drywell and torus in parallel (the previous preferred method of inerting vice inerting the torus and drywell individually). This change was made due to a recently identified concern that a design basis loss of coolant accident, coincident with operations to purge or inert the drywell, could overpressurize the standby gas treatment system, despite automatic system isolation at the onset of the accident. This issue was discussed in inspection report 97-03 and is the subject of an inspector follow item (97-03-01). Previously, the drywell and torus were purged at the same time, and the licensee considered that this likely resulted in better mixing of the air and nitrogen. The licensee further considered that the close proximity of the sample point to the torus nitrogen inlet resulted in an erroneously low oxygen concentration being indicated during the May 8 inerting operation, leading operators to secure the nitrogen purge too early. Therefore, VY station management directed that inerting of the torus would be resumed in parallel with the plant shutdown, with the shutdown to be terminated when torus air space oxygen concentration was reduced to less than four percent.

Torus inerting was commenced at 9:45 a.m. At 12:00 noon on May 12, torus air space oxygen concentration was measured to be 1.0 percent, and torus inerting was secured at 12:30 p.m. Power reduction for the reactor shutdown was stopped at 12:40 p.m., at 94 percent power. At 2:00 p.m., the licensee exited TS 3.7.A.8, and commenced power escalation at 2:30 p.m. The plant returned to full power operation at 5:22 p.m. The licensee instituted daily torus oxygen sampling until consistent oxygen concentration had demonstrated that adequate inerting had been performed, and verified that the source of oxygen had not actually been an air leak into the torus.

The licensee initiated an event report (ER No. 97-0516) to document this event and to initiate corrective action. At the close of the inspection period, this event report remained open.

c. Conclusions

A weekly surveillance revealed that oxygen concentration in the torus air space was greater than allowed by Technical Specification (TS). Prompt action was taken to verify this result and to reduce oxygen concentration to within TS limits. The condition was preliminarily determined to be due to inadequate nitrogen purging during containment inerting following plant startup. While the licensee's response to the high oxygen concentration was found acceptable, the inspectors were concerned that the licensee controls were not successful in avoiding this condition. Pending further inspector review of the cause of this event, this issue is unresolved **(URI 97-04-02)**.

O1.4 Unusual Event Declared due to Indication of a Possible Seismic Event

a. Inspection Scope (71707)

The inspector reviewed the events surrounding the licensee's declaration of an Unusual Event (UE) in response to a plant seismic monitor alarm.

b. Observations and Findings

At 7:03 a.m. on May 31, 1997, operators received a seismic monitor alarm. There were no other indications that a seismic event (earthquake) had occurred. The licensee declared an Unusual Event at 7:25 a.m., based on procedure AP-3125, "Emergency Plan Classification and Action Level Scheme," entry criteria U-5-c, "Any earthquake sensed on-site as recognized by observation or detection." The states of Vermont, New Hampshire, and the Commonwealth of Massachusetts were notified, and a one-hour emergency notification (EN 32420) was made to the NRC as required by 10 CFR 50.72.

The licensee responded in accordance with operating procedure OP-3127, "Natural Phenomena." This included visual inspection of selected plant structures for possible damage, and completion of a seismic damage indicator walkdown of plant systems. No evidence of earthquake damage was observed. Examination of data retrieved from the seismic monitor revealed that only one of the three accelerometers had detected motion. Given that no other monitoring stations had detected an earthquake, the licensee concluded that the cause of the seismic monitor alarm had been a spurious indication from a single accelerometer. The licensee terminated the UE at 9:35 a.m. Subsequent troubleshooting of the seismic monitor demonstrated that the suspect accelerometer had failed.

c. Conclusions

The VY staff responded appropriately to the seismic monitor alarm and the declaration of an Unusual Event was in accordance with their emergency procedures. However, the inspector considered that the procedural requirement to declare an Unusual Event based on a single indication was overly conservative. Allowance to verify that a seismic event has actually occurred prior to making an event determination would potentially avoid the unnecessary mobilization of state and federal emergency response organizations.

O4 Operator Knowledge and Performance

O4.1 Operator Performance Observations

a. Inspection Scope (71707)

As discussed in section O1.1, the cause of the April 24 reactor scram was personnel error. During this inspection period, the inspectors noted other instances of weak operator performance:

b. Observations and Findings

During a planned shift of shutdown cooling from residual heat removal (RHR) loop A to loop B, a licensed operator attempted to start a B-loop RHR pump while its suction valve was still closed.

While placing the second feedwater regulating valve in service during the plant startup from the outage, the shift supervisor became engaged in non plant-related activities in the control room that reduced his effectiveness at monitoring the evolution.

The pre-job brief for single rod scram testing on April 24 did not include a discussion of possible problems and actions to be taken. When a rod failed to scram, attention was initially focused on determining whether an error had been made in the test equipment setup rather than on restoring the plant condition to normal. Later, the shift supervisor directed that the rod be fully reinserted using the manual rod control system.

c. Conclusions

The inspector was concerned that the number and nature of these instances were above normal, with respect to operations staff performance in recent inspection periods. This concern warrants additional management attention to ensure that this in not an early indication of a performance trend. These observations and concern were discussed and acknowledged by VY station management.

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.

b. Observations, Findings, and Conclusions

The inspector observed all or portions of the following maintenance activities:

- Disassembly and inspection of one of the scram solenoid pilot valves (SSPVs) suspected of having excessive wear, observed on April 26, 1997. SSPV malfunction is discussed in section M2.2 of this report; the inspector observed that only the suspect solenoid valve plunger showed indication of wear (black dust), and that the other solenoid valve plunger appeared as if new. No deficiencies were noted in the conduct of this maintenance.

- Replacement of air pressure regulators for the emergency diesel generator service wate/ flow control valves, observed May 22, 1997. This maintenance was performed to address the possibility that non-nuclear safety (NNS) regulator malfunction could cause the SW flow control valves to fail shut and thereby render the EDGs inoperable; this problem is discussed further in section E1.3 of this report. The NNS regulators were replaced in-kind with units that had undergone commercial grade dedication. No deficiencies were noted in the conduct of this maintenance.

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 all or portions of the following surveillance tests:

Single rod scram time test for rod 06-11, observed on April 24, 1997. This testing was performed in response to the slower than expected individual rod scram time that was observed during the April 24 reactor scram, and led to the discovery that the scram solenoid pilot valve assembly was defective. This material problem is discussed further in section M2.2 of this report; performance observations from this testing are discussed in section O4.1 of this report.

Main turbine minimum speed oil trip test, observed on May 8, 1997. This test was performed during the main turbine startup in preparation for synchronizing the main generator to the grid. The test was well controlled and was completed satisfactorily.

Torus-to-drywell vacuum breaker cycling, observed on May 30, 1997. Along with a review of the procedure, the pre-job brief included discussion of how communications would be handled, problems that had previously occurred, and actions to be taken if problems were encountered. The test was completed satisfactorily.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Planned Mini-Outage for Repair of Main Steam Bypass Valve V2-77

a. Inspection Scope (62707)

The inspector reviewed the scope of maintenance activities that were completed during the April 24 - May 7 maintenance outage.

b. Observations and Findings

The principle activity that required the plant to be shut down and cool down was repair of the main steam bypass valve, V2-77. This valve had developed a body-to-bonnet leak soon after startup from the 1996 refueling outage, and attempts to perform an on-line temporary leak repair had been unsuccessful; these activities were discussed in inspection report 96-11. The plan was to repair the existing valve, but a replacement valve was ready for installation, if repair proved unfeasible. No other major maintenance activities were originally planned to be worked, and the outage was projected to last approximately two days. However, several emergent problems forced extension of the outage to May 7. The problem that most significantly affected the schedule was an oil leak that developed on the main transformer; this item is discussed further in section M2.3 of this report. Other emergent issues included:

- Scram solenoid pilot valve refurbishment/replacement; this item is discussed in section M2.2 of this report

- Repair of a small oil leak on the "B" recirculation pump motor

- Replacement of a leaking valve body seal on each the "A" and "C" main steam relief valves

- Rerouting of several electrical cables to resolve cable separation concerns; this issue was discussed in inspection report 97-03, and is further addressed in section E1.1 of this report

c. Conclusions

The licensee's decision to shut down for repair of V2-77 was the result of a thorough review of the available repair options. Licensee preparations for this maintenance were thorough. The outage duration was extended primarily due to emergent maintenance that could not have been foreseen going into the outage. These issues were appropriately addressed prior to plant restart.

M2.2 Scram Solenoid Pilot Valve Malfunction

a. Inspection Scope (62707)

During post-scram review of individual control rod scram times, the licensee noted that rod 06-11 was significantly slower that all of the other rods. The scram time from position 48 to 46 for rod 06-11 was 0.526 seconds, as opposed to the core average of 0.280. The licensee initiated additional testing of rod 06-11 to determine the cause of the slow scram time.

b. Observations and Findings

On the afternoon of April 24, with the plant still in HOT SHUTDOWN, single rod scram time testing was attempted on rod 06-11. However, the rod did not insert when scrammed, remaining instead fully withdrawn at 48 steps. Troubleshooting by instrument and controls (I&C) personnel identified the cause to be that the scram solenoid pilot valve (SSPV) assembly was not venting in response to a scram signal, thereby preventing the hydraulic control unit (HCU) scram valves from operating to scram the rod. VY informed the NRC of the failed scram time test as required by 10 CFR 50.72 (EN 32263).

During the 1996 refueling outage, VY had replaced all SSPVs. The replacement valves were developed and qualified for this application in a cooperative effort between VY and a valve manufacturer (Automatic Valves, or AVCO), in response to historic difficulties that had been experienced with existing SSPVs. The new valves differ from existing SSPVs in that they do not use elastomer diaphragms. They are configured such that both SSPVs for a particular HCU are contained in a common valve body, whereas the original SSPVs were two independent units. Although VY is currently the only licensee that uses this dual solenoid valve unit in an SSPV application, these valves are used in different applications by other licensees. VY also uses these valves to operate the scram discharge volume vent and drain valves, and the main steam isolation valves.

Soon after startup from the 1996 refueling outage, VY noted that several of the new SSPV units were producing a buzzing noise. VY inquired to AVCO regarding the noise, and the response was that such noise was expected with AC-powered solenoids (60-cycle hum) and that it did not constitute a problem. Nevertheless, VY tracked the condition, periodically noting which units were buzzing and how loud they were buzzing (based on a qualitative scale, developed specifically for this condition). RPS surveillance testing made it possible to identify which of the two solenoids was buzzing by noting whether the noise stopped when a half scram signal was inserted. This accumulated information became significant when it was recognized that the SSPV that failed on April 24 (HCU 06-11) was one of the units that had been buzzing.

VY sent the failed SSPV unit to AVCO for cause determination. No prior troubleshooting of the unit was attempted by VY, so that the as-failed condition would not be disturbed. AVCO determined that the cause of failure was that one of the solenoid plungers was bound in the energized position (pilot valve remains closed). The SSPV solenoids de-energize to scram and both solenoids pilot valves must be open for the associated rod to scram. The top of the plunger was found to have a peened edge around the upper end. The peened material had caught in the plunger guide and caused the plunger to stick. AVCO concluded that the cause of the plunger deformation was slight, cyclic movement of the plunger, induced by the 60-cycle AC power to the solenoid, which was causing the top of the plunger to strike the plunger backseat. This condition had been the source of the buzzing noise and, over time, had produced wear and deformation of the plunger end. AVCO notified the NRC that they were initiating the 10 CFR 21 process for reporting of a defective component (EN 32253).

Based on this proposed failure mechanism, VY inspected the remaining SSPVs that had been producing a buzzing noise. For all nine units inspected, the solenoid that had been identified to be buzzing (through I&C's earlier informal monitoring) was found to have a worn plunger. The wear was evidenced by the presence of black dust. The black dust had also been present in the SSPV that was sent to AVCO, and had been identified by them to be the same material as the plunger (400-series stainless steel). By unaided visual inspection, none of the worn plungers showed evidence of deformation or peening. However, the degree of wear (that is, the amount of black dust) was found to correlate roughly with the level of noise that the solenoid had been making. The nine associated solenoids that had not been buzzing showed no indication of wear.

The worn plungers were replaced and the SSPVs were tested to verify that the buzzing noise had been eliminated. In one case, the noise persisted after plunger replacement, so the entire SSPV unit was replaced. The replaced components were sent to AVCO for additional evaluation. Single rod scram time testing was performed on all rods associated with the SSPV refurbishment/replacement, with satisfactory results.

Although the root cause of failure was still under investigation by AVCO, VY concluded that the inspections of the nine SSPV units had demonstrated that the buzzing noise was a conclusive indicator of incipient solenoid failure. To support continued operation pending completion of the root cause determination, VY instituted a weekly inspection of all SSPVs by I&C personnel, and shiftly checks for abnormal noise, to be performed by operations personnel. A basis for maintaining operation, BMO 97-19, was generated to document this approach.

c. Conclusions

The conclusion that solenoid buzzing could be used as an indicator of incipient failure was adequately supported by the SSPV inspection results. Increased monitoring of the SSPVs for noise was an appropriate interim corrective action. Resolution of this issue will be tracked by the licensee's BMO, and will be progressed by the inspectors as a matter of routine inspection.

M2.3 Main Station Transformer Oil Leak

Following the plant shutdown on April 24, plant workers identified an oil leak on one of the gasketed manways to the main transformer (T-1). A number of repair alternatives were considered, but VY concluded that gasket replacement was the most prudent resolution. During the process of manway removal and gasket replacement, additional inspections of transformer internals were conducted. These inspections identified additional repair work which required partial oil draindown and an increase in the original transformer work scope. The transformer problems and repair work had no direct nuclear safety impact. However, main transformer reliability and availability does affect balance of plant related transients and challenges to the reactor protection system. It was the inspector's understanding that the transformer repairs were prudently authorized, but not essential to continued safe and reliable operation of the generating unit. Licensee staff inspection of the transformer following it being placed in service on May 8, 1997 identified no discrepancies.

III. Engineering

E1 Conduct of Engineering

E1.1 Emergency Diesel Generator Potential Common Mode Failure

On May 21, 1997, the control room operators notified the NRC in accordance with 10 CFR 50.72 (EN 32370) of a condition outside their design basis which potentially could have rendered both emergency diesel generators (EDGs) inoperable. The EDG service water (SW) flow control valves (FW-104-28A and B) are air-operated and supplied via non-nuclear safety related (NNS) 100/35 psig pressure regulators in the NNS instrument air system. The failure of the NNS pressure regulators could cause the FCV-104-28A and B valves to fail in the closed position, which would isolate service water cooling flow through the EDG lubricating oil and jacket water cooling heat exchangers.

The discovery of this EDG system design vulnerability was made by the NRC Architect Engineering Team inspection staff. A more detailed examination and summary of this finding will be documented in their inspection report. The resident inspectors verified that, upon recognition of this design vulnerability, the VY staff made an operability assessment of each EDG and properly notified the NRC per 10 CFR 50.72 of this design issue. As discussed in section M1.1 of this report, the inspector witnessed and verified prompt replacement of the NNS pressure regulators with similar commercially dedicated regulators. An inspector followup item will track this issue pending issuance of the inspection report and final characterization of the inspection finding. **(IFI 97-04-03)**

E1.2 480 Volt AC System

a. Inspection Scope (37551)

The inspector reviewed the licensee's protection and coordination for the rotating uninterruptible power supply (RUPS), and the 480 Volt Bus 9 (supply bus) and MCC 89A (load bus) to assess the coordination of the RUPS with its associated buses.

b. Observations and Findings

The inspector reviewed calculation VYC-1087, Attachment B, page 36, 480 Volt SWGR Bus 8 and 9 Breaker Settings, Rev 1, dated July 8, 1992. This document provided the protection and coordination time-current characteristics for Bus 8 and 9 related protective devices. The inspector observed that the information for the RUPS ac feeder protective devices included the conductor sizes for the motor feeders. The inspector observed that the ac motor feeder included a 350 MCM conductor with a transition to an AWG No. 1 conductor local to the RUPS. The inspector questioned the apparent lack of overcurrent protection for the AWG No. 1 conductors on the RUPS ac input power circuit. In response, the licensee produced an internal schematic for the RUPS, drawing 5020-11266, Sheet 1, Rev.2, dated December 30, 1996, which also indicated AWG No. 1 conductors located between the internal RUPS ac breaker and the ac motor. The licensee's drawing confirmed the RUPS ac breaker was rated 150 amps consistent with the coordination curve. The inspector confirmed that the 1990 National Electrical Code, Table 310-16, permitted an AWG No. 1 conductor with a 90°C rating to continuously carry 150 amps. The inspector also confirmed the nameplate full load current of the ac motor was 105 amps.

The inspector observed that the RUPS was not the largest load on Bus 8 or 9. Both buses have a 250-HP control rod drive water pump and a 125 HP reactor building cooling water pump. In addition, Bus 9 also has a 250-HP fire water pump. Licensee Event Report 50-271/92-018 addressed a previous problem that had resulted in a transient low voltage when starting the fire pump with reduced bus voltage. In the past, this had resulted in a swap-over of the RUPS from its ac source to dc power. The inspector reviewed an evaluation, Yankee Nuclear Services Division (YNSD) had performed in response to VY Service Request PM No. 1350. That evaluation, contained in file VYE 89/92, Bus 9 Voltage Analysis for RUPS Evaluation, dated December 4, 1992, concluded, based on a computer model (DAPPER), that under reduced bus voltage of 460 Vac, starting the fire pump motor could result in the observed transfer of the RUPS from ac to dc supply power. The inspector was informed that this evaluation formed the basis for a modification to the RUPS trip circuit performed under JO920068. The inspector reviewed the results of that evaluation and questioned the input data and results. In response, the YNSD agreed that there appeared to be errors in the model used for the evaluation. However, these apparent errors would result in an even lower voltage than the YNSD model had calculated. The inspector was informed YNSD would issue an event report to document the discrepancy and initiate appropriate corrective action to re-evaluate the model used for the fire pump starting evaluation. The details of JO920068 were not available during this inspection. These items will remain open pending NRC review of the revised modeling of the fire pump starting and retrieval of JO920068 from the historical records **(IFI 50-271/97-04-06)**.

The inspector requested information on the Bus 9 load and breaker settings to confirm the coordination of the Bus 9 incoming breaker with the largest loads on the bus. The inspector reviewed selected coordination sheets from drawing B-191305, 480 V SWGR Bus 8 and 9, CAPTOR Project VY480SI, Rev. 0, dated July 8, 1992, and proposed changes, dated August 9, 1996. The inspector confirmed that sufficient coordination existed for the feeder breakers to Bus 9 and all the load breakers. The inspector confirmed that the existing and future settings contained in the coordination package for the Bus 9 incoming and tie breakers provided sufficient protection for both the station service transformer and the 480 Volt bus. The inspector also confirmed the fire pump motor (FPM) coordinated with the bus feeder breakers during starting of the FPM.

The licensee provided breaker information for the RUPS ac load side connection which was based on the original static inverter. The licensee indicated they had planned an update for the coordination study for these breakers during 1997 for consistency.

c. Conclusions

The inspector concluded the coordination curve for the ac supply side of the RUPS should have clarified the apparent lack of protection for the AWG No. 1 transition cable to the ac motor. This was considered a weakness in the calculation. The inspector concluded the coordination of the 480 Volt Bus 9 feeder breaker with the RUPS and the 250 HP motors were acceptable.

E1.3 Rotating Uninterruptible DC Power Supply

a. Inspection Scope

The dc power supply for the rotating uninterruptible power supplies (RUPS) consists of the batteries and a dc machine. The batteries had been the dc supply for the original static UPS. The dc machine acts as a battery charger when driven from the ac motor and a dc motor when it is driving the ac generator upon loss of the ac supply. The inspector reviewed the basis for the selection, sizing and test acceptance criteria for the batteries associated with the RUPS.

b. Observations and Findings

The inspector reviewed calculation VYC-1630, Battery Sizing Calculation for 400 VDC RUPS Batteries, dated February 26, 1997, to assess the design requirements for the RUPS batteries. The inspector found that the sizing calculation was based on a minimum permissible battery terminal voltage of 360 Volts, derived a duty cycle from a previous ECCS Integrated Automatic Initiation Test, and included appropriate margins for battery aging and minimum temperature. The calculation estimated the maximum current seen by the battery would be 75 amps during stroking of valve V10-27A. In addition, the calculation held that current for five minutes. The inspector found the calculation acceptable.

The inspector reviewed the test procedures for the safety-related batteries associated with the RUPS batteries-1A and 1B. The inspector reviewed the results of the last performance test performed on battery RUPS-1A on September 5, 1993 (Procedure OP 4209, Rev. 6). The results of the discharge test indicated the battery had a capacity of 110% of the manufacturer's rating.

The inspector reviewed the latest service test results obtained on October 10, 1996, for battery RUPS-1B (Procedure OP4219, Rev. 6). The inspector found that the acceptance criteria only required the demonstration that the battery was capable of supplying the UPS with the power necessary for the UPS to supply its ac loads during the integrated ECCS test. No minimum battery voltage was specified and the data indicated the voltage at the battery dropped to 385 Volts after 173 seconds. The inspector confirmed the longest stroke time permitted for MOV V10-27B by the RHR System Surveillance Test, OP 4124.01, Rev.46, dated April 24, 1997, was 44.45 seconds. The inspector found that the post-modification test that was performed following installation of the RUPS indicated the RUPS low voltage dc trip was set at 365 +/-2 Volts. Therefore, the inspector found the test acceptable.

c. Conclusions

The inspector concluded the RUPS batteries were adequately sized for their present application and had additional margin beyond their design basis.

E2 Engineering Support of Facilities and Equipment

E2.1 Post-Modification Test of the Vernon Tie 5 kV Cable

a. Inspection Scope

The inspectors reviewed the maintenance and testing performed on the 5.0 kV cable that forms part of the power supply from the Vernon hydroelectric station to assess its reliability.

b. Observations and Findings

The inspectors found that the feed had been upgraded in 1993 by installing a new buried 15 kV line from Vernon to the VY site (EDCR 90-412.) This EDCR was originally installed to upgrade the feed to support 10 CFR 50.63, the Station Blackout Rule. A new transformer was also installed at the VY end of the line to interface with the VY 4160 volt bus. A new section of 5 kV cable was installed from the transformer to a manhole where it was spliced to a section of the existing 5 kV cable into the plant.

The inspectors observed that the installation included high-direct-voltage testing (Hi-pot) of the new cables and an insulation resistance (IR) test of the existing 5 kV cable section. The inspectors reviewed the test results of the Hi-pot testing that was performed in June 1993 and noted that the new 15 kV and 5 kV cables appeared to have successfully withstood a dc proof test at 65 kV and 35 kV respectively.

The inspector questioned why the existing cable was also not subjected to a dc Hi-pot. The existing cable section had been installed in underground duct banks, subject to moisture, and normally energized, but unloaded, for most of its installed life. This type of installation has historically been responsible for most of the medium voltage cable failures reported in the electrical power industry. The licensee indicated hi-pot testing for the existing cable section was not required by engineering design change request (EDCR) 89-407 and the insulation resistance test showed good IR values. The inspector reviewed the post-modification test data and confirmed the IR testing performed on August 20, 1993, produced excellent results with the minimum value recorded of 375 Megohms. These readings included both the new and old sections of the 5 kV cable and the splice joining them together.

The licensee indicated that when apparent lightning damage was found on another section of the old abandoned Vernon tie 5 kV cable, the old, still-used section of cable that was the transition into the plant was given a reduced voltage (10 kV) hi-pot test. The inspector reviewed the results of hi-pot tests that were performed on July 18, 1995, and concluded, based on a review of IEEE Std. 400-1991, Guide for Making High-Direct-Voltage Tests on Power Cables in the Field, that the step voltage method was superior to the original high voltage proof test performed in 1993. The inspector also confirmed the leakage currents at the 10 kV test voltage were equal to or less than 1 microamp.

The inspectors reviewed the background for determining the reduced test voltage and compared it to other guides, recommendations and practices used throughout the electric industry. The inspector noted that there is no universal standard in test voltages for cables installed for more than five years. Test voltages for 5 kV cables range from 10 to 25 kV and often refer the user to the manufacturer for their recommendation. The inspector confirmed the licensee had contacted various manufacturers, other utilities and industry experts during a previous review for testing associated with the startup transformer cables in 1993. Based on the industry practices and the review of the 1995 hi-pot test results, the inspector found the test voltage used was acceptable.

c. Conclusions

The inspectors concluded the installation and followup testing of the Vernon tie was acceptable based on industry test practices and the Vernon tie cable test results, which showed good insulation resistance and adequate dielectric strength.

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 RHR Service Water Flow Requirements

On May 6, 1997, the control room operators notified the NRC in accordance with 10 CFR 50.72 (EN 32285) of a potentially degraded/unanalyzed condition involving the residual heat removal service water (RHRSW) system. Examination of the UFSAR accident analyses assumptions by the NRC Architect Engineering Team identified that the minimum RHRSW flow through the RHR heat exchangers (2,700 gpm) may not be achieved because the existing flow instrument uncertainty of plus or minus 200 gpm. Station Operating Procedure (OP)-2124 instructs operators to limit RHRSW system flow to a maximum of 2,700 gpm. Consequently, the actual flow may exceed the established limit (potentially adversely impacting heat exchanger design flow limits) or fall short of the prescribed cooling flow (potentially compromising torus heat removal and containment response assumptions).

The inspector verified the interim actions taken by the VY staff to limit continued reactor plant operations to Connecticut River water temperatures of 70 degrees F and below which will ensure the facility remains within established ultimate heat sink heat removal capacity assumptions. This issue will be tracked via an Inspection Follow Item pending final characterization of this inspection finding and issuance of the inspection report. **(IFI 97-04-04)**

E7.2 Individual Plant Examination 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.

Failure of Various Non-Seismic Piping Could Affect Safety Related Equipment

On May 20, 1997, the control room operators notified the NRC in accordance with 10 CFR 50.72 (EN 32362) of a condition outside the plant's design basis, involving the postulated failure of non-seismic piping which could adversely impact safety related equipment. Specifically, the failure of service water supply lines in the HVAC room, service water lines to non-safety related components in the reactor building (recirculation motor-generator set lube oil coolers), and fire protection suppression water system piping in the reactor core isolation cooling (RCIC) room have all been postulated to result in flooding of the safety related components in the immediate and/or adjacent areas. These postulated failures and their consequences were not previously identified in VY's 1988 Flooding Study.

The inspector reviewed the licensee's immediate systems' operability assessments which concluded that the identified piping, although not seismic category I, was of sufficient design and strength to withstand design basis earthquake dynamic loading. In addition, established operator actions for dealing with internal plant flooding and formal Emergency Operating Procedures provide appropriate guidance for dealing with these types of postulated events. The inspector found this initial operability assessment satisfactory and the interim compensatory actions appropriate. Pending final resolution, this design concern will be tracked as an Inspector Followup Item. **(IFI 97-04-05)**

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Follow-up Item 50-271/97-02-07: offsite electrical power sources

a. Inspection Scope (37551)

By letter dated February 25, 1997, the NRC staff requested additional information pertaining to the VY offsite power system design. The NRC staff was completing a review of older operating plants' offsite power systems based upon the lessons learned from the Maine Yankee Independent Safety Assessment. The review was focused on the adequacy of the delayed offsite power circuits as required by General Design Criteria (GDC) 17, and in particular, the reliance upon main and unit auxiliary transformers to backfeed power to the onsite distribution system.

VY responded to the request for additional information by letter dated March 26, 1997. The March 26, 1997 letter established that no analysis had been completed to demonstrate that the main transformer backfeed delayed offsite power source could be established in sufficient time to prevent fuel design limits and design conditions of the reactor coolant pressure boundary from being exceeded. In lieu of this analysis, the licensee relied upon the Vernon Tie (a second delayed offsite power circuit) to restore electrical power (within ten minutes via switches in the control room) until the main transformer backfeed could be made available (in approximately six hours). The March 26, 1997 letter also established that VY considered the Vernon Tie as acceptable for compliance with both GDC 17, as a delayed access source and 10 CFR 50.63, "Station Blackout Rule" as an alternate alternating current (AC) power source.

Following review of VY's March 26 response, the NRC conducted a telephone discussion with the VY staff followed by a letter dated April 17, 1997 summarizing the NRC staff's understanding of the offsite power systems and their conclusion that the Vernon Tie cannot serve as one of the GDC 17 offsite power sources and as an alternate AC power source. The VY staff attempted to clarify their licensing and design basis of the offsite power systems via VY letter dated April 24, 1997.

b. Observations and Findings

Via conference calls between the NRC staff and VY management on April 25, 1997, the NRC staff informed VY that GDC 17 was satisfied via the 345 kv auto-transformer (for immediate access power) and the Vernon Tie (for delayed access power). Further, that the Vernon Tie could not be credited for satisfying 10 CFR 50.63. In addition, the NRC staff considered this issue not to be a unit restart impediment, provided VY submitted their plans within 30 days for complying with 10 CFR 50.63. Via letters dated April 29, 1997 and May 1, 1997, the licensee formalized their commitments for complying with 10 CFR 50.63 and the NRC staff acknowledged the acceptability of VY's schedule to achieving full compliance, respectively.

By subsequent letter dated May 29, 1997, VY docketed their plans to implement modifications, with supporting analysis and licensing bases, to establish the main transformer back feed capability as the GDC 17 delayed access power circuit. In addition, VY docketed their plans to initiate the appropriate licensing actions to support the re-approval of the Vernon Tie as the 10 CFR 50.63 Station Blackout alternate AC power source.

c. Conclusions

The licensee satisfies 10 CFR Part 50, Appendix A, GDC 17, "Electric Power Systems' and has committed to comply with 10 CFR 50.63 prior to start-up from the 1998 refuel outage. This inspection follow-up item is closed. NRC staff review of VY's proposed modifications and licensing changes will be examined during a future inspection period.

E8.2 (Closed) LER 50-271/97-007: inadvertent primary containment isolation system actuation due to a spurious spike on a reactor building vent radiation monitor, dated May 21, 1997. VY staff response was appropriate for this spurious radiation monitor electronic noise spike and subsequent ventilation systems automatic isolation and initiation. Proper verification measures were initiated to confirm radiological conditions did not cause the event and that automatic system responses were as designed. The control room staff appropriately notified the NRC in accordance with 10 CFR 50.72 (reference Event No. 32192, dated April 21, 1979.

E8.3 (Closed) LER 50-271/97-008: plant scram due to procedural non-compliance and failure to perform self-verification during nuclear instrumentation calibration, dated May 23, 1997. This event is discussed in section O1.1 of this report.

E8.4 (Closed) LER 50-271/97-009: lack of specificity in plant Technical Specifications results in operation of the plant service water systems which was inconsistent with prescribed limiting conditions for operation and testing requirements, dated May 21, 1997. The inspector noted that the root cause of this issue could not be determined because of the length of time this TS requirement had been in effect (since initial licensing in 1971). The interim and more restrictive administrative limits placed upon service water subsystem operation were determined appropriate by the inspector. The VY staff plans to remedy this TS discrepancy upon NRC staff review and approval of their improved TSs, targeted for 1998. Also, reference inspection report 97-02, section E7.1 and inspector follow item 97-02-08.

E8.5 (Closed) LER 50-271/97-010: individual control rod drive scram time greater than normal due to manufacturing defect in scram solenoid pilot head assembly, dated May 21, 1997. This event is discussed in section M2.2 of this report.

E8.6 (Open) Violation 50-271/96-09-06, inadequate battery service test acceptance criteria

a. Inspection Scope (92701)

Inspection report 50-271/96-09 discussed a problem with test control for the main station batteries. The licensee had failed to incorporate any appropriate acceptance criteria for the battery service test. The criteria that was provided had no basis in any design document and failed to consider the minimum battery terminal voltage used to determine the acceptable operation of safety-related dc equipment. The inspector reviewed the licensee's corrective action in response to Violation 96-09-06.

b. Observations and Findings

In their response letter, BVY 96-161, dated December 20, 1996, the licensee indicated four corrective actions would be taken to avoid further violations. The licensee indicated that the first three items (update the calculation, perform a consistency review of the battery test procedures and define ownership of design basis calculations) would be completed by April 30, 1997, and the remaining item (update procedure OP 4215) would be completed by June 30, 1997. These corrective actions were further defined by the licensee in their Event Report (ER) No. 96-0748.

The inspector confirmed that calculation VYC-298, Battery Sizing Calculation for Vermont Yankee Station Batteries A-1 and B-1 was revised (Rev.10) on April 22, 1997, and calculation VYC-1349, 125 Volt DC Voltage Drop, was revised (Rev.1) on April 30, 1997. The inspector also confirmed copies of the calculations were forwarded to the electrical maintenance engineer at VY. At the time of this inspection, the Main Station Battery Test Procedure, OP 4215, had not yet been updated to be consistent with the new calculations.

The inspector confirmed that the Electrical/I&C Design Group established a Calculation Tracking System in response to the NOV. The controlling list of calculations was issued on April 7, 1997. The tracking system lists the calculations by number, responsible engineers, affected calculations and procedures and pending revisions to the base calculation. The inspector noted that even though calculation VYC-1349 was listed in the cover memorandum, the tracking system failed to identify a pending revision against the calculation. The inspector was later provided a copy of the June 1, 1997, issue of the tracking system and noted it correctly indicated calculation VYC-1349 had been revised.

The inspector noted ER 96-0748 did not limit this corrective action to just Electrical/I&C Design Engineering but it was assigned to Design Engineering in general. The inspector also noted the Plant Operating Review Committee (PORC) review of the ER specifically indicated all Design Engineering departments should evaluate if a similar tracking system is necessary. As of the close of this inspection, it did not appear that any other discipline had initiated an evaluation of a similar calculation tracking system. The inspector did confirm that Vermont Yankee Design Engineering Procedure (VYDEP) 15, Calculations, had been revised (Rev.2) on March 31, 1997, to emphasize the relationship of calculations to procedures and other documents.

The inspectors confirmed that the licensee had performed a consistency review of the surveillance procedures associated with the batteries defined in the technical specifications. The licensee issued an interoffice memorandum, dated May 20, 1997, which documented the review of the service test procedures for batteries AS-2, the ECCS batteries and the main station batteries against their design basis calculations. The licensee indicated that all the associated battery calculations were revised in 1997 and the procedures are being revised to include the new load profiles.

The inspector noted the absence of the RUPS batteries from the May 20th memorandum. The licensee explained that the RUPS batteries were purposefully not included in the memorandum because they are tested with the actual loads during their surveillance test and are not tested to a calculated load profile. The inspector found this acceptable.

c. <u>Conclusions</u>

The inspector concluded the licensee had not completed all the corrective actions in response to the notice of violation. The licensee had updated the battery sizing and voltage drop calculations. These calculations had been transmitted to the site in response to the new calculation ownership process. The inspectors noted that the licensee is continuing to review these calculations.

IV. Plant Support

S1 Conduct of Security and Safeguards Activities

a. Inspection Scope

Determine whether the security program, as implemented, met the licensee's commitments in the NRC-approved security plan (the Plan) and NRC regulatory requirements. The security program was inspected during the period of May 27-30, 1997. Areas inspected included: management support and audits; effectiveness of management controls; alarm stations and communications; training and qualification; and the vehicle barrier system.

b. Observations and Findings

Management support was evident based on the effective implementation of the security program as documented in this report. The Security Manager's position in the organizational structure and reporting chain permits management's awareness of issues and concerns, management controls for identifying, resolving, and preventing programmatic problems were effective, and audits were thorough and in-depth. Alarm station operators were knowledgeable of their duties and responsibilities and security training was being performed in accordance with the NRC-approved training and qualification (T&Q) plan.

Based on the inspection of the land vehicle barriers and discussions with plant engineering and security management, the inspector determined that the licensee's provisions for land vehicle control measures satisfy regulatory requirements and licensee commitments. After review of UFSAR and Section 5.3.2 of the Plan, entitled "Vehicle Searches," the inspector determined by observing security force members performing vehicle searches, discussing with security supervision, and reviewing applicable procedures and records that vehicles were being properly searched prior to permitting protected area access as required in the Plan and applicable procedures.

c. Conclusions

The inspector determined that the licensee was conducting its security and safeguards activities in a manner that protected public health and safety and that the program, as implemented, met the licensee's commitments and NRC requirements.

S2 Status of Security Facilities and Equipment

S2.1 Alarm Stations and Communications

a. Inspection Scope

Determine whether the Central Alarm Station (CAS) and Secondary Alarm Station (SAS) are: (1) equipped with appropriate alarm, surveillance and communication capability, (2) continuously manned by operators, and (3) use independent and diverse systems so that no single act can remove the capability of detecting a threat and calling for assistance, or otherwise responding to the threat, as required by NRC regulations.

b. Observations and Findings

Observations of CAS and SAS operations verified that the alarm stations were equipped with the appropriate alarm, surveillance, and communication capabilities. Interviews with CAS and SAS operators found them knowledgeable of their duties and responsibilities. The inspector also verified through observation and interviews that the CAS and SAS operators were not required to engage in activities that would interfere with the assessment and response functions, and that the licensee had exercised communications methods with the local law enforcement agencies as committed to in the Plan.

c. Conclusion

The alarm stations and communications met the licensee's Plan commitments and NRC requirements.

S5 Security and Safeguards Staff Training and Qualification

a. Inspection Scope

Determine whether members of the security organization are trained and qualified to perform each assigned security-related job task or duty in accordance with the T&Q Plan.

b. Observations and Findings

On May 29, 1997, the inspector observed tactical response training. The training involved the proper use of cover and concealment, tactical movement, weapons manipulation, and shooting under stress. Based on observations, the training was properly controlled, safety was stressed at all times, and the instructors were knowledgeable of the subject matter. Additionally, the inspector interviewed a number of SFMs to determine if they possessed the requisite knowledge and ability to carry out their assigned duties.

c. Conclusions

The inspector determined that training had been conducted in accordance with the T&Q Plan. Based on responses to the inspector's questions, the training provided by the security training staff was found to be effective.

S6 Security Organization and Administration

a. Inspection Scope

Conduct a review of the level of management support for the licensee's physical security program.

b. Observations and Findings

The inspector reviewed various program enhancements made since the last program inspection, which was conducted in July 1996. These enhancements included the procurement of tactical response training aids and ongoing range improvements. The inspector reviewed the Security Manager's position in the organizational structure and reporting chain. The Security Manager reports to the Technical Services Superintendent, who reports to the Plant Manager, who reports directly to the Vice-President of Operations. Additionally, the inspector noted that the access authorization and fitness-for-duty programs, being safeguards related, report directly to the Security Manager.

c. Conclusions

Management support for the physical security program was determined to be effective. No problems with the organizational structure that would be detrimental to the effective implementation of the security and safeguards programs were noted.

S7 Quality Assurance in Security and Safeguards Activities

S7.1 Effectiveness of Management Controls

a. Inspection Scope

Determine if the licensee has controls for identifying, resolving, and preventing programmatic problems.

b. Observations and Findings

The inspector reviewed the licensee controls for identifying, resolving, and preventing security program problems. These controls included the implementation of a departmental self-assessment program, which includes the performance of post assessments by security supervision and the performance of the NRC-required annual quality assurance (QA) audits. The licensee also utilizes industry data, such as violations of regulatory requirements identified by the NRC at other facilities, as criteria for self-assessment. The inspector reviewed documentation applicable to the performance of the self-assessment program and noted that 51 self-assessments were conducted in 1996 and, as of this inspection, 26 self-assessments were performed during 1997.

Additionally, the inspector noted that an average of 67 post assessments are performed per month by security shift supervision. The inspector determined, based on a review of the safeguards event logs, self-assessments, and post assessments that personnel performance errors were minimal.

c. Conclusions

The inspector concluded that controls were effectively implemented to prevent and resolve potential weaknesses.

S7.2 Audits

a. Inspection Scope

Review the licensee's Quality Assurance (QA) report of the NRC-required security program audit to determine if the licensee's commitments as contained in the Plan were being satisfied.

b. Observations and Findings

The inspector reviewed the 1996 QA audit of the security program, conducted October 21-24, 1996, (Audit No. VY-96-04) and the 1997 combined QA audit of the fitness-for-duty (FFD)/access authorization (AA) programs, conducted February 12-23, 1997, (Audit No. VY-97-19). The audits were found to have been conducted in accordance with the Plan and FFD rule. To enhance the effectiveness of the FFD/AA audit, the audit team included one independent technical specialist.

The security audit report identified no findings. The combined FFD/AA audit identified four findings and six recommendations. The findings involved general employee training weaknesses concerning information on the effects of prescription and over-the-counter drugs on job performance and chemical test results, two documentation issues involving AA records, and the accuracy of the random drug testing pool. The audit results had been disseminated to the appropriate levels of management. The inspector determined, based on discussions with security management and FFD/AA supervision, that the responses to the audit have not been finalized as of the inspection. Those findings will be reviewed during a subsequent inspection.

c. Conclusions

The review concluded that the audits were comprehensive in scope and depth, that the findings were appropriately distributed, and that the audit program was being properly administered.

S8 Miscellaneous Security and Safety Issues

S8.1 Vehicle Barrier System (VBS)

Background

On August 1, 1994, the Commission amended 10 CFR Part 73, "Physical Protection of Plants and Materials," to modify the design basis threat for radiological sabotage to include the use of a land vehicle by adversaries for transporting personnel and their hand-carried equipment to the proximity of vital areas and to include the use of a land vehicle bomb. The amendments require reactor licensees to install vehicle control measures, including vehicle barrier systems (VBSs), to protect against the malevolent use of a land vehicle. Regulatory Guide 5.68 and NUREG/CR-6190 were issued in August 1994 to provide guidance acceptable to the NRC by which the licensees could meet the requirements of the amended regulations.

A February 23, 1996, letter from the licensee to the NRC forwarded Revision 27 to its physical security plan that detailed the actions implemented to meet the requirements of 10 CFR 73.55 (c)(7),(8), and (9) and the design goals of the "Design Basis Land Vehicle" and "Design Basis Land Vehicle Bomb." A NRC June 19, 1996, letter advised the licensee that the changes submitted had been reviewed and were determined to be consistent with the provisions of 10 CFR 50.54(p) and were acceptable for inclusion in the NRC-approved security plan.

This inspection, conducted in accordance with NRC Inspection Manual Temporary Instruction 2515/132, "Malevolent Use of Vehicles at Nuclear Power Plants," dated January 18, 1996, assessed the implementation of the licensee's vehicle control measures, including vehicle barrier systems, to determine if they were commensurate with regulatory requirements and the licensee's physical security plan.

a. Inspection Scope

The inspector reviewed documentation that described the VBS and physically inspected the as-built VBS to verify it was consistent with the licensee's summary description submitted to the NRC.

b. Observations and Findings

The inspector's walkdown of the VBS and review of the VBS summary description disclosed that the as-built VBS was consistent with the summary description and met or exceeded the specifications in NUREG/CR-6190.

c. Conclusion

The inspector determined that there were no discrepancies in the as-built VBS or the VBS summary description.

S8.2 Bomb Blast Analysis

a. Inspection Scope

The inspector reviewed the licensee's documentation of the bomb blast analysis and verified actual standoff distances provided by the as-built VBS.

b. Observations and Findings

The inspector's review of the licensee's documentation of the bomb blast analysis determined that it was consistent with the summary description submitted to the NRC. The inspector also verified that the actual standoff distances provided by their as-built VBS were consistent with the minimum standoff distances calculated using NUREG/CR-6190. The standoff distances were verified by review of scaled drawings and actual field measurements.

c. Conclusion

No discrepancies were noted in the documentation of bomb blast analysis or actual standoff distances provided by the as-built VBS.

S8.3 Procedural Controls

a. Inspection Scope

The inspector reviewed applicable procedures to ensure that they had been revised to include the VBS.

b. Observations and Findings

The inspector reviewed the licensee's procedures for VBS access control measures, surveillance and compensatory measures. The procedures contained effective controls to provide passage through the VBS, provide adequate surveillance and inspection of the VBS, and provide adequate compensation for any degradation of the VBS.

c. Conclusions

The inspector's review of the procedures applicable to the VBS disclosed no discrepancies.

V. Management Meetings

X.1 Exit Meeting Summary

The inspectors met with licensee representatives periodically throughout the inspection and following the conclusion of the inspection on June 10, 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.

X.2 Management Meeting Summary

On April 30, 1997, representatives of VY, General Electric, and Yankee Atomic Electric Company met with the NRC staff in Rockville, MD, to discuss current and future fuel cycle operation at VY. A summary of this meeting was provided by VY via correspondence to the NRC, BVY 97-69, dated May 22, 1997.

On May 15, 1997, VY managers met with the NRC Region I staff in King of Prussia, PA, to discuss performance improvements in the engineering area. Materials that were presented during the meeting are attached to this report.

X.3 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. Since the UFSAR does not specifically include security program requirements, the inspectors compared licensee activities to the NRC-approved physical security plan, which is the applicable document. While performing the inspection discussed in this report, the inspector reviewed Section 5.3.2 of the Plan, Revision 27 dated February 23, 1996, titled, "Vehicle Searches." The inspector determined, by observing security force members performing vehicle searches, discussions with security supervision and reviews of applicable procedures and records, that vehicles are being properly searched prior to permitting protected area access as required in the Plan and applicable procedures.

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
81700	Physical Security Program for Power Reactors
TI 2515/132	Malevolent Use of Vehicles at Nuclear Power Plants

ITEMS OPENED, CLOSED, AND DISCUSSED

OPEN

VIO 97-04-01	Violation of Technical Specification 6.5, "Plant Operating Procedures"
URI 97-04-02	Torus oxygen concentration outside TS limits
IFI 97-04-03	Potential for loss of EDG SW flow due to SW flow control valve air pressure regulator failure
IFI 97-04-04	RHR service water flow requirements
IFI 97-04-05	Failure of various non-seismic piping could affect safety related equipment
IFI-97-04-06	Electrical circuit model to support evaluation of voltage drop during start of the fire pump

CLOSED

IFI 97-02-07	Offsite electrical power sources
LER 97-007	Inadvertent primary containment isolation system actuation, May 21, 1997
LER 97-008	Plant scram, May 23, 1997
LER 97-009	Lack of specificity in plant TS
LER 97-010	Individual control rod drive scram time greater than normal

DISCUSSED

URI 97-03-02	Operability assessments for the identified cable separation

PARTIAL LIST OF PERSONS CONTACTED

G. Maret, Plant Manager
S. Jefferson, Assistant to Plant Manager
F. Helin, Tech. Services Superintendent
E. Lindamood, Director of Engineering
K. Bronson, Operations Manager
M. Watson, I&C Manager
M. Desilets, Radiation Protection Manager
R. Gerdus, Chemistry Manager
G. Morgan, Security Manager
C. Nichols, Electrical and Controls Maintenance Manager
J. Moriarty, Security Operations Specialist
L. Pitts, Security Technical Assistant
W. Peterson, Quality Assurance (QA) Manager, Yankee Atomic Energy Company (YAEC)
A. Wonderlick, QA Engineer, YAEC
F. Harper, Project Manager, The Wackenhut Corporation (TWC)
E. Wright, Security Operations Supervisor, TWC
G. Sherer, Security Project Coordinator, TWC
J. Jasinski Security Training Supervisor, TWC
P. Corbett, Project Engineering Manager, VY
B. Donovan, Electrical Maintenance Engineer, VY
D. Maidrand, Electrical (DC) System Engineer, VY
D. Philips, Manager, Electrical and I&C Maintenance Engineering, VY
D. Jannary, Manager, Electric and I&C Design Engineer, YNSD
P. Johnson, Sr. Electrical Engineer, YNSD
R. Cox, Electrical Engineer, YNSD
R. Moschella, Electrical Engineer, YNSD
R. Vibert, Electrical Engineer, YNSD

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
SFM	security force members
QA	quality assurance
the Plan	NRC-approved physical security plan
PA	protected area
T&Q	training and qualification
IDS	intrusion detection systems
CAS	central alarm system
SAS	secondary alarm system
UFSAR	Updated Final Safety Analysis Report
CCTV	closed circuit television
VBS	vehicle barrier system

33

ENCLOSURE 3

VERMONT YANKEE ENGINEERING UPDATE
NRC Region I Meeting, May 15, 1997

Vermont Yankee
Engineering Update

NRC Region 1 Meeting

May 15, 1997

Agenda

I. Introduction

II. Overview of Engineering Organization

III. System Engineering

IV. Design Engineering Initiatives

V. Configuration Management Improvement Project

Priorities

- System Engineering
- Design Basis
- Corrective Action

Overview of VY Integrated Engineering Organization

- **DA Reid**, VP Operations
  - **G. Maret**, Plant Manager
  - **EV Lindamood**, Director of Engineering
    - **DE Yasi**, Nuclear Services Manager
    - **M. Mills**, Fluid Systems Engineering Manager
    - **RG January**, Electrical/I&C Engineering Manager
    - **JH Callaghan**, Mechanical Engineering Manager
    - **DP Corbett**, Projects Manager
    - **D Calsyn**, Technical Programs Manager
  - **D Legere**, System Engineering Manager

System Engineering

- Mission & Responsibilities
- Staffing
- Changes

System Engineering

- Maintenance Rule

System Engineering

- Operating Experience

System Engineering

- Performance Monitoring

Design Engineering
Lessons Learned

- Leadership
- Work Management
- Ownership

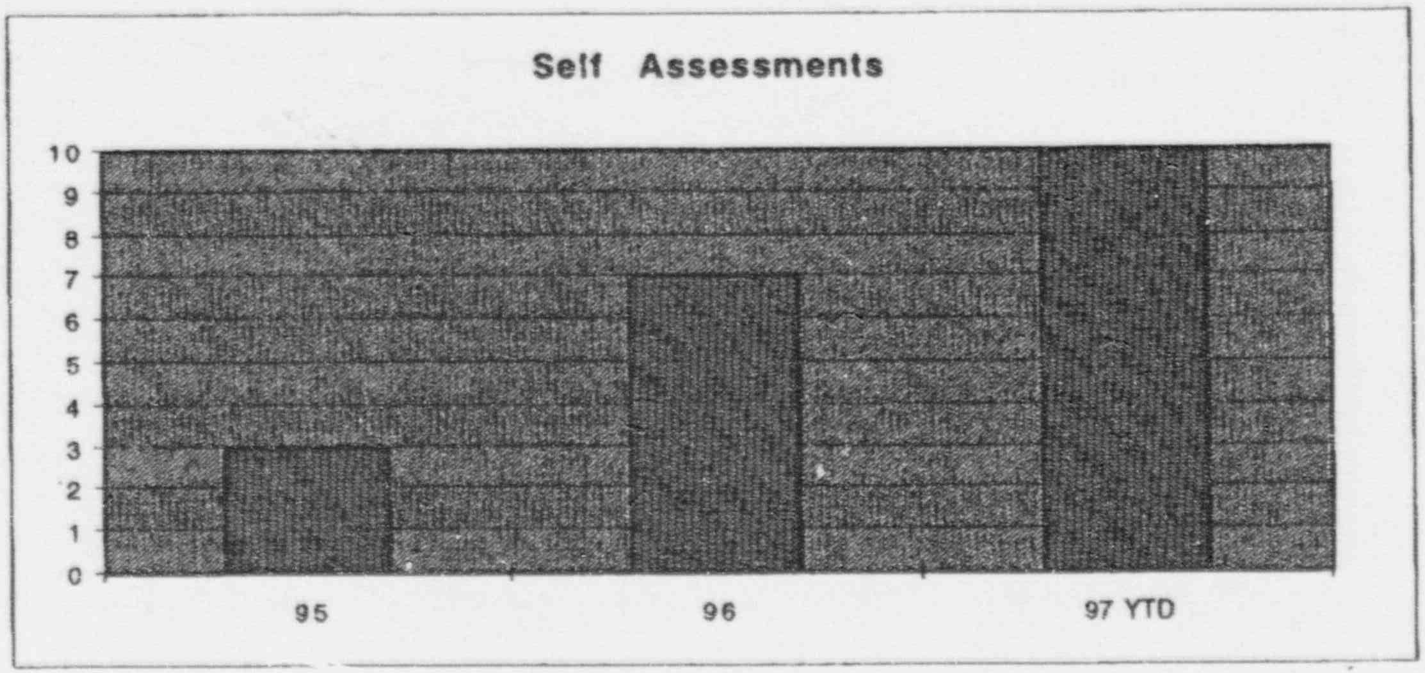
People Initiatives

- Safety Culture
- Ownership
- Teamwork

Process Initiatives

- Work Management
- Self Assessments

Self Assessments



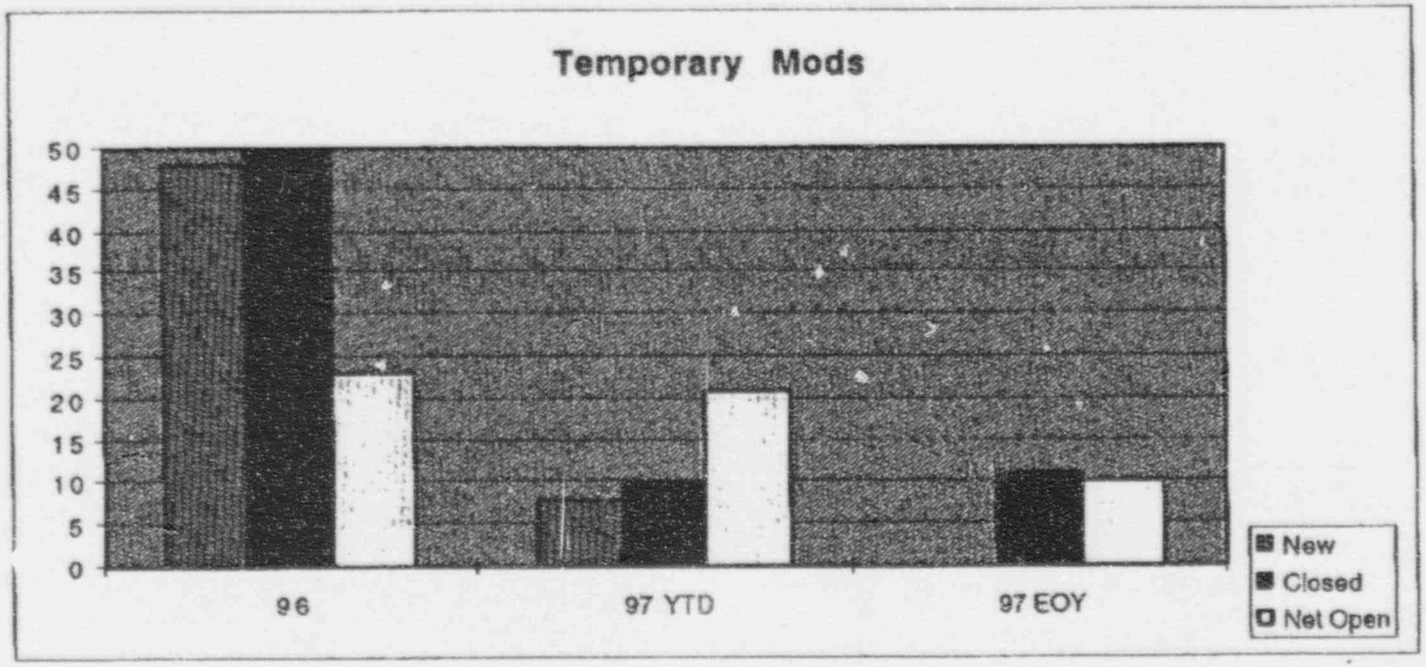
Project Initiatives

- Reduce Operator Workarounds
- Reduce Engineering Backlog

Operator Workarounds

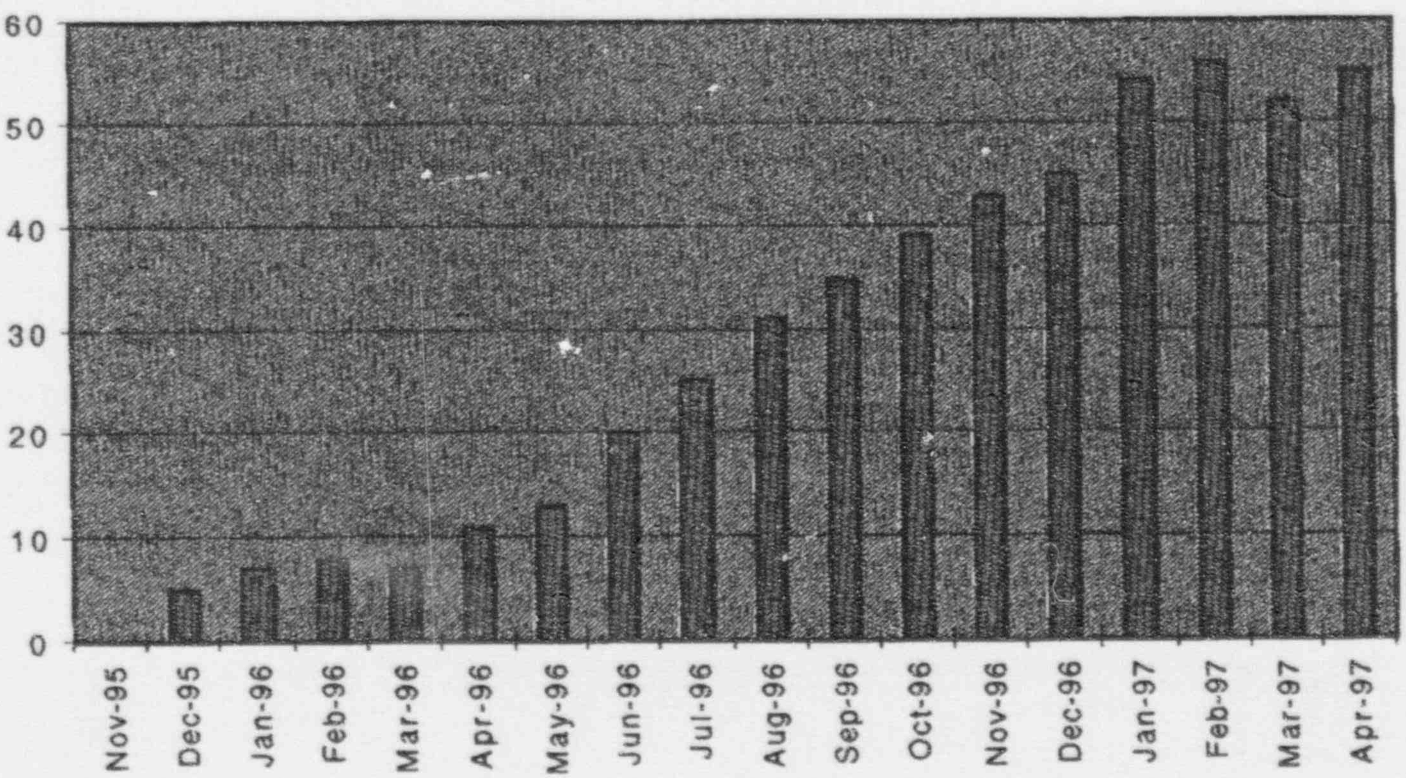
- *13 Workarounds at beginning of 97*
- *1 Eliminated during Mini Outage*
- *4 Others expected to be Eliminated in 97*
- *Temp Mods*

Temporary Mods



Event Report Closeout

Design Engineering
Overdue Event Report History



Configuration Management Improvement Project (CMIP)

- Objectives

- Key Elements

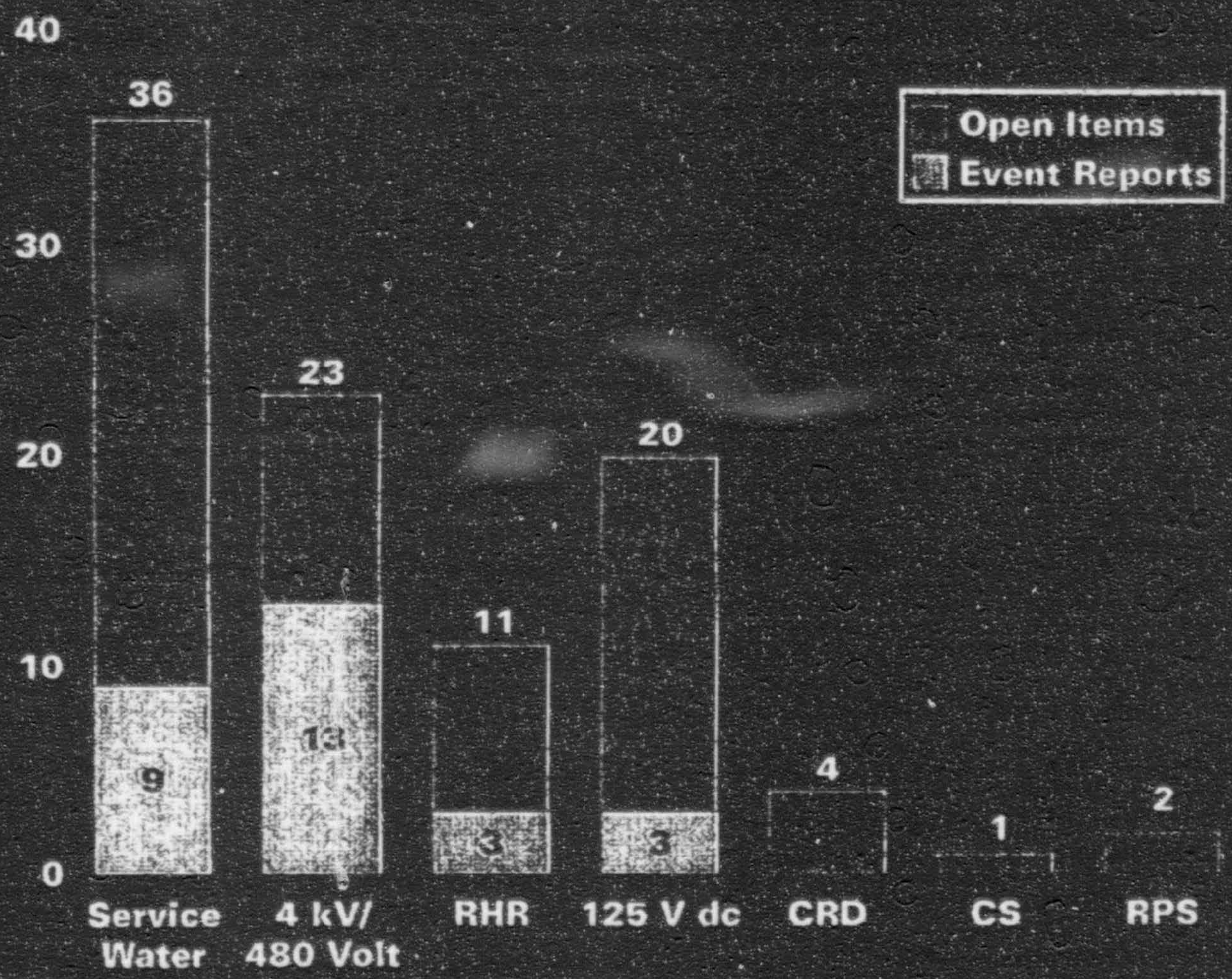
Overview of CMIP Organization

- CMIP PROGRAM MANAGER
  - DBD VALIDATION
  - DBD PREPARATION/ REVIEW/ APPROVAL
    - GE (PREPARERS)
    - DUKE (PREPARERS)
    - D.E., OPERATIONS, SYSTEM ENGINEERING (REVIEW/APPR)
  - FSAR VERIFICATION
  - OPEN ITEM RESOLUTION
  - CONFIGURATION MANAGEMENT PROCESS IMPROVEMENTS
    - INTEGRATED/ STREAMLINED PROCESSES

Design Basis Documents
(DBD)

- Plan
- Progress

Open Items/Event Reports



DBD Validation

- Plant Operation vs. Design Basis

CM Process Improvements

- Streamline
- Integrate
- Control