U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.: 50-293

Report No.: 50-293/88-07

Licensee: Boston Edison Company
800 Boylston Street
Boston, Massachusetts 02199

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: January 20 - March 5, 1988

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Approved By: [signature] 5-6-88
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Reactor Projects Section No. 3B

Inspection Summary:

Areas Inspected: Routine resident inspection of plant operations, radiation protection, physical security, plant events, maintenance, surveillance, outage activities, and reports to the NRC. The inspection consisted of 575 hours of direct inspection. Principal licensee management representatives contacted are listed in Attachment I to this report. The inspection findings identified in Augmented Inspection Team Report 50-293/87-53 have been summarized and assigned unresolved item numbers to facilitate NRC followup. This information was provided to the licensee, and is included as Attachment II.

Results:

Violation: Failure to establish adequate procedures and to perform adequate technical review were evident during the blackout diesel generator testing and the plant process computer point tie-in activities (Section 3.b and 4.b, VIO 88-07-01).

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Unresolved Items:

1. Lifting of leads in safety-related circuits, while conducting E203 activities, may not be subject to adequate post work tests. (Section 4.h, UNR 88-07-02).

2. Control and documentation of worker overtime does not appear to fully satisfy the intent of NRC guidelines. (Section 5, UNR 88-07-03).

Concern: Weaknesses in control of maintenance activities resulted in an unnecessary engineered safety feature actuation (Sections 4.f and 4.h).

Strength: Licensee self critique in response to the unusual event on February 11, 1988 was prompt, thorough and effective (Section 4.e).

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DETAILS

1.0 Summary of Facility Activities

The plant has been shutdown for maintenance and to make program improvements since April 12, 1986. The reactor core was completely defueled on February 13, 1987 to facilitate extensive maintenance and modification of plant equipment. The licensee completed fuel reload on October 14, 1987. Reinstallation of the reactor vessel internal components and the vessel head was followed by completion of the reactor vessel hydrostatic test. The primary containment integrated leak rate test was also completed during the week of December 21, 1987.

During this report period, the licensee performed post-modification/ maintenance testing of plant equipment including the blackout diesel generator as described in Section 3.b.

2.0 Followup on Previous Inspection Findings (Modules: 92701 and 92702)

(Closed) Violation 85-03-05, Failure to Test Scram Trip Logic and Alarms as Required by Technical Specification Table 4.1.1

Four instances of failure to perform adequate surveillance testing were identified and included in the violation. Specific corrective actions implemented by the licensee for each of the four instances are described below. In their response to Notice of Violation (NOV) 85-03-05, dated May 17, 1985, the licensee contested two of the examples; Item 2 and Item 3. The inspector has reverified the original validity of the violation. Further, the 1985 response does not appear to reflect current licensee management philosophy, and corrective actions implemented by the licensee appear to have addressed the deficiencies identified by Items 2 and 3 in NOV 85-03-05. The technical adequacy of surveillance testing was raised as a general area of concern during 1986. Since that time the licensee has implemented an extensive program to review and upgrade testing. NRC evaluation of this upgrade effort is the topic of existing unresolved item 50-293/86-21-03.

Item 1: On December 24, 1984, and January 7, 1985, the APRM inoperative scram trips were not functionally tested prior to declaring them operable, while the reactor was in the startup mode. A functional test was eventually performed on January 13, 1985. In response to the violation the licensee revised procedure 8.M.1-3.1, APRM Setdown Functional Test. This test is performed weekly when the mode switch is not in run, and prior to reactor startup. It was modified to include verification that APRM inoperative trips are functional and that the trips result in a half scram. This revised testing appears to satisfy Technical Specification requirements. The inspector had no further questions.

Item 2: The licensee restarted the plant and placed the reactor mode switch in run on December 29, 1984. The APRM high flux scram trips were not functionally tested until January 4, 1985. The Technical Specifications require testing "as soon as practicable after returning to the run mode." In their response dated May 17, 1985 the licensee denied the violation based on a non-conservative interpretation of "as soon as practicable", and the contention that procedure 2.1.1, Startup from Shutdown, did not require performance of the testing until 60 percent power and this power level had not been reached. While the Technical Specification requirement is not specific, a five day delay in performance of this testing is clearly not consistent with the intent of the specification. Therefore, after consulting with NRC Region I management, the inspector concluded that issuance of this violation had been justified.

The licensee has revised procedure 2.1.1 to require performance of this testing at less than 40 percent power, or within four hours of entering the run mode. This revision should ensure that the testing is performed in a timely manner. The inspector discussed this nonconservative Technical Specification interpretation with licensee management. During the inspectors' exit, the Site Director stated that the nonconservative interpretation was not consistent with current management philosophy. The inspector had no further questions.

Item 3: The APRM downscale scram trips are required to be operable with the mode switch in run. The licensee restarted the plant on December 29, 1984, and again on January 9, 1985. The APRM downscale scram trips however, were not functionally tested prior to declaring them operable while the reactor was in the run mode on either occasion. In their response dated May 17, 1985, the licensee denied this violation and cited surveillance procedure 8.M.1-3.1, APRM Setdown Functional, as having satisfied the test requirement prior to placing the mode switch in run. Review of the revision of procedure 8.M.1-3.1 in effect at the time indicates that only functioning of the downscale light on the APRM panel was tested. The functioning of the output relay and subsequent output relay contact closure in the reactor protection system (RPS) was not tested. The definition of instrument functional testing states that instrument channel response, alarm and initiating action should be verified. Observation of a local alarm light is not adequate verification of the initiating action. Therefore, after consulting with NRC, Region I management, the inspector concluded that issuance of this violation had been justified.

The inspector reviewed the current technical adequacy of procedure 8.M.1-3.1 which functionally tests APRM trips with the mode switch not in run. The procedure has been revised to directly verify the operation of the downscale scram trip output relay contact which initiates the scram. This test is scheduled weekly when the mode switch is not in run. In addition, procedure 2.1.1, Startup from Shutdown, requires completion of 8.M.1-3.1 prior to startup. Procedure 2.1.1 has also been revised to require performance of procedure 8.M.1-3, APRM Functional, within four hours after placing the mode switch in run, or prior to 40 percent power. Procedure 8.M.1-3 functionally tests APRM trips with the mode switch in run, including initiating the appropriate half scrams. With the incorporation of these changes the licensee appears to be performing the required APRM functional tests. The inspector had no further questions.

Item 4: On January 2, 1985, the stop valve closure alarm was not functionally tested prior to declaring the turbine stop valve (SV) closure instrumentation operable with the mode switch in run. This instrumentation is required to be operable with turbine first stage pressure greater than 305 psig and the reactor in the run mode. The licensee's test procedures did not include steps to perform this testing for either the stop valve or main steam isolation valve (MSIV) closure alarms. This deficiency was identified by a licensee Quality Assurance (QA) audit conducted in September 1984. A formal Deficiency Report (DR) was issued on November 5, 1984, however, corrective action was not initiated until January 28, 1985. Temporary Modification (TM) 85-11 was implemented on February 14, 1985 to improve circuit testability, and surveillance procedures were revised to perform adequate tests. It is noted in NRC Inspection Report 50-293/85-03 that while the licensee had identified the deficiency, effective corrective actions were not taken in that four calendar months, and significant time with the unit at power, had transpired before action was taken. During the current inspection, the inspector confirmed that procedures for testing of the SV and MSIV instrumentation circuits have been permanently revised to ensure performance of the required testing. The licensee's responsiveness to QA findings was the subject of violation 50-293/86-14-07 and has subsequently improved.

In each case discussed above the licensee appears to have implemented adequate corrective actions. The inspector had no further questions. This item is closed.

(Update) Unresolved Item (86-19-03), Standby Gas Treatment System (SGTS) Single Failures

This item was last updated in inspection report 50-293/87-45. The licensee previously identified several SGTS single failure vulnerabilities and submitted appropriate 10 CFR Part 21 reports. A plant design change (PDC) was implemented to address the problems. The licensee's corrective actions were reviewed and evaluated by the inspector as detailed in inspection report 50-293/87-45. This item remained open pending inspector review of a design evaluation performed for the licensee by a contractor. During this inspection period the inspector reviewed the contractor report and licensee actions to disposition the findings. Generally, the findings presented in the contractor report were minor in nature and were adequately dispositioned by the licensee. However, the inspector questioned the licensee closeout of two items. No post-modification test was performed to verify that an acceptable cooling flow rate will be achieved through the train crosstie duct. A minimum flow rate must be maintained through this path to cool the charcoal filters of the standby train. The licensee's response to this item was that available calculations provide sufficient assurance, and that no functional test is needed. The inspector requested that the licensee provide these calculations and any additional justification available. The contractor also questioned the sizing of the orifice installed in the crosstie duct. The PDC installed a system discharge flow switch which will start the standby train at a flow rate of 2000 CFM. If the orifice is sized to allow the minimum cooling flow rate with the running train operating at a design flow of 4000 CFM, then a significant reduction in the train flow, possibly to as low as 2000 CFM, could result in insufficient cooling flow through the standby train. The inspector questioned the adequacy of the 2000 CFM setpoint. If degradation of the operating train occurs, flow could drop significantly and still remain above the setpoint. The licensee stated that the setpoint had been raised and that the new setpoint combined with existing calculations would support the adequacy of the design. The licensee stated that this information would be made available. The inspector will review supporting information when provided by the licensee.

3.0 Routine Periodic Inspections (Modules: 71707, 71710, 62703, 61726, 71881, 37700, 71709, 71714, 72701, 92701 and 92703)

The inspectors routinely toured the facility during normal and backshift hours to assess general plant and equipment conditions, housekeeping, and adherence to fire protection, security and radiological control measures. Inspections were conducted between ten p.m. and six a.m. on February 12, February 26, March 3, March 4, and March 5, 1988 for a total of 12 hours. Inspections were also conducted on holidays and weekends on January 23, January 24, February 21, February 28, and March 5, 1988 for a total of 23 hours. Ongoing work activities were monitored to verify that they were being conducted in accordance with approved administrative and technical procedures, and that proper communications with the control room staff had been established. The inspector observed valve, instrument and electrical equipment lineups in the field to ensure that they were consistent with system operability requirements and operating procedures.

During tours of the control room the inspectors verified proper staffing, access control and operator attentiveness. Adherence to procedures and limiting conditions for operations were evaluated. The inspectors examined equipment lineup and operability, instrument traces and status of control room annunciators. Various control room logs and other available licensee documentation were reviewed.

The inspector observed and reviewed outage, maintenance and problem investigation activities to verify compliance with regulations, procedures, codes and standards. Involvement of QA/QC, safety tag use, personnel qualifications, fire protection precautions, retest requirements, and reportability were assessed.

The inspector observed tests to verify performance in accordance with approved procedures and LCO's, collection of valid test results, removal and restoration of equipment, and deficiency review and resolution.

Radiological controls were observed on a routine basis during the reporting period. Standard industry radiological work practices, conformance to radiological control procedures and 10 CFR Part 20 requirements were observed. Independent surveys of radiological boundaries and random surveys of nonradiological points throughout the facility were taken by the inspector.

Checks were made to determine whether security conditions met regulatory requirements, the physical security plan, and approved procedures. Those checks included security staffing, protected and vital area barriers, personnel identification, access control, badging, and compensatory measures when required.

a. Routine Observations

On January 23, 1988, at about 9:30 a.m., the control room received a report of flooding in the high pressure coolant injection (HPCI) system pump room. Investigation confirmed that approximately three inches of water had accumulated on the floor in the area. The Watch Engineer entered Emergency Operating Procedure (EOP)-4, Secondary Containment Control. Water level of greater than one inch on the HPCI pump room floor is an entry condition of EOP-4. All systems discharging into the sump were isolated. The area drain valve was checked open, and an operator was dispatched to manually start one of the two sump pumps. After manually starting a pump the operator noted that a rubber hose had been wrapped around the sump level float switch. The hose prevented the float switch from actuating and starting the pumps on increasing sump level. The hose was removed and the second pump automatically started. The water was quickly processed to rad waste. Health physics surveys indicated contamination levels of between 1K and 350K dpm per 100 square centimeters. The source of the water was routine equipment leakage. The licensee estimates that it took at least two shifts for the water to build up in the room. One non-licensed operator and one licensed reactor operator who should have completed shift tours in the area were suspended for failure to perform the required surveillance. Because the level of water in the room remained low no equipment damage resulted. There were no personnel contaminations associated with the incident.

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During a routine operator tour on January 26, 1988, the licensee again identified several inches of water on the HPCI pump room floor. One of the sump pumps was manually started. The operator also observed that the pumps had not automatically started on increasing level because a pipe had been placed on top of the sump float switch, preventing the switch from actuating. Subsequent licensee investigation identified that I&C technicians routinely used the pipe to block the switch and allow sump levels to increase for float switch testing. The technicians had failed to remove the pipe after a previous test. A licensee critique of this occurrence revealed that the procedure for testing and adjusting the sump switch was inadequate. The procedure provided no guidance on how to raise sump level and therefore, the technicians improvised the method which blocked the float switch. The licensee has revised the procedure and the technicians have been made aware of the proper methods for conducting this test. The inspector reviewed licensee responses to these two occurrences and had no further questions.

During the week of February 29, 1988, the inspector accompanied operators for portions of routine operator tours. The inspector reviewed the logs for their completeness and accuracy. The inspector also interviewed the operators for their knowledge of the systems and components. No discrepancies were noted.

b. Plant Maintenance and Outage Activities

-- Blackout Diesel Post Modification Testing

During the current outage the licensee installed a third emergency diesel generator for use in the event of a station blackout. Although installation and operability of the third EDG is not a license requirement, its availability is intended to provide an alternate status power source in the event of a loss of offsite power to the site. Construction, component testing, and final diesel acceptance testing was completed during this inspection period. Procedures TP 88-09, Electric Plant Line-up for Blackout Diesel Generator Load Test, Revision 0, and TP 87-267, Pre-Operational Test of the Blackout Diesel Generator, Revision 0, were issued after approval by the station Operations Review Committee (ORC). TP 88-09 controls the significant equipment lineups and temporary alterations required to allow complete testing of the diesel. TP 87-267 prescribes the performance testing of the machine after establishment of the required system configuration.

Immediately prior to licensee implementation of the testing the inspector reviewed these two procedures for technical adequacy. The inspector identified that TP 88-09, Revision 0, was inadequate in that in four separate locations within the procedure an unanticipated "B" emergency diesel generator (EDG) start signal would have been generated. Although procedure steps had been included to disable the "B" EDG output breaker, no steps had been included to prevent the machine from automatically starting, or to prepare for the start. Performance of the TP as written would have resulted in unnecessary cold starting of the "B" EDG and the resultant challenge to installed ESF actuations. The inspector informed the licensee of this concern. The licensee confirmed the existence of this deficiency, placed all further EDG testing on hold, and initiated a detailed technical review. In addition to confirming the presence of the inadvertent "B" EDG start signals the licensee review identified that drywell unit coolers would also automatically have started. Procedure TP 88-09 was revised to prevent these equipment actuations. The inspector informed the licensee that the failure to perform adequate technical review, and to establish an adequate procedure is an apparent violation of Technical Specification 6.8.A (VIO 88-07-01).

The inspector reviewed the revised TP 88-09 and witnessed its implementation. Control of the procedure execution was generally good. Conduct of diesel load test TP87-267 was also observed. The inspector noted that personnel involved in the testing, including the control room staff, were cautious and displayed a conservative approach to test performance.

c. Cold Weather Protection

During routine tours of the plant, the inspector examined systems susceptible to freezing to verify the presence and operability of heat tracing, space heaters, and insulation. The licensee's program and procedures were also reviewed to determine whether the licensee has maintained effective implementation of the program of protective measures for extreme cold weather conditions to ensure equipment operability.

The plant has been in a prolonged shutdown condition since April 12, 1986. The plant heating system provides heat for process buildings including the screen house and the diesel generator building. Discussions with the licensee indicated that heat tracing was applied to the following systems and that all other safety-related piping susceptible to freezing was either buried or in a heated area: 1) the main stack sample line, 2) the fire sprinkler piping for "B" diesel generator, 3) the jockey fire pump low pressure sensing line, and 4) the fire sprinkler piping for the outside bottle storage area.

The operability of heat tracing for the main stack sample line, the fire sprinkler piping for "B" diesel generator, and the jockey fire pump low pressure sensing line are checked during a routine (daily/ weekly) surveillance. The inspector noted that the heat trace on the fire water sprinkler piping for the outside bottle storage area was inoperable and an hourly fire watch patrol has been established by the licensee. The licensee informed the inspector that a permanent enclosure will be built for the bottle storage area and a space heater will be provided to preclude freezing.

The inspector reviewed the following to determine if any other systems could be subject to freezing:

-- IE Bulletin 79-24, Frozen Lines
-- Licensee response to IEB 79-24, dated October 24, 1979
-- Licensee Event Reports for the years 1984, 1985, 1986 and 1987

The inspector had no further questions.

d. Region I Temporary Instruction 87-07, Licensee's Fitness for Duty Policy and Reporting Requirements

The Commission Policy Statement on fitness for duty of nuclear power plant personnel, published on August 4, 1986, in the Federal Register (51 FR 27921) requires the NRC staff to evaluate the effectiveness of licensee efforts in the area. Early in 1987, copies of all licensee fitness for duty programs were collected and reviewed. Based upon the information provided and questions raised about fitness for duty programs, further information was needed to evaluate the programs on a consistent basis. During this inspection period, the inspector examined records and data relating to the experience associated with the licensee's fitness for duty program. Information was provided as requested in the NRC Region I Temporary Instruction 88-01.

e. Temporary Instruction 2515/90: Licensee's Implementation of Multiplant Action Item B-58, Scram Discharge Volume (SDV) Capability

On June 1980 during a routine shutdown of the Browns Ferry Unit 3 reactor, a manual scram from about 36% power failed to fully insert approximately 40% of the control rods. The root cause was determined to be a problem with the SDV header. The followup to this event at other BWRs revealed a number of deficiencies with the SDV headers.

The corrective measures to this problem were divided into a short-term program and a long-term program. The short-term actions were implemented by IE Bulletins 80-14 and 80-17 and their supplements. The objective of the long-term program was the improvement of the SDV design. (SDV design details vary from plant to plant.) There are three primary areas of concern addressed by the long-term program.

The first concern was to improve the hydraulic coupling between the SDV headers, which comprise most of the free volume in the SDV, and the instrumented volume (IV), which is physically lower than the headers and is intended to detect any water accumulation and to scram the reactor before the headers fill. It was discovered at many sites that the relatively long pipes connecting the SDV headers to the IV had considerably greater hydraulic resistance than the IV drain line. Thus, a rapid ingress of water would tend to fill up the headers, leaving the IV nearly empty because it was draining as fast as water spilled in through the long connecting pipe.

Second, the reliability of the float switches in the IVs needed to be improved. The recommended solution was the addition of redundant and diverse water sensors.

Finally, it was recommended that the IVs be modified to prevent damage to the level sensors by hydrodynamic forces and water hammer in the IV during a scram.

Temporary Instruction 2515/90 provides inspection guidance to assure that facility modifications installed at all boiling water reactors meet the criteria and technical bases that were endorsed in a NRC generic safety evaluation report dated December 1, 1980 for use in implementing permanent system modifications to identified deficiencies.

The inspector conducted an extensive review of licensee design documents and physical installations to insure that the present plant configuration meets the requirements of the NRC confirmatory Order to Boston Edison Company dated June 24, 1983. The results of this review are as follows:

-- Scram Discharge Header Sizing and Hydraulic Coupling to the Instrument Volume

  Generic Safety Evaluation Report (SER) to all BWR licensees, dated December 9, 1980 shows that the Pilgrim design for scram discharge instrument volume's sizing is acceptable. To meet the improved hydraulic coupling requirements the licensee has installed two new scram discharge instrument volumes which are coupled to the scram headers via six inch lines. Review of design documents which installed this modification verified that the hydraulic coupling is now satisfactory.

-- Automatic Scram on High Scram Discharge Instrument Volume (SDIV) Level

  Review of Technical Specifications, reactor protection system drawings and surveillance tests verify that a high SDIV level scram exists and is routinely tested.

-- Instrument Taps not on Connecting Piping

Visual examination determined that the installed instrument taps are on the vertical instrument volume not on connecting piping.

-- Diverse and Redundant Level Indication

The installed instrumentation at Pilgrim includes two differential pressure cells and three RTD level sensors on each of the two instrument volumes. These diverse instrument types use four separate sets of instrument taps and by their arrangement meet the requirement to have diverse and redundant instrumentation. This instrumentation provides continuous level indication, alarms, rod withdrawal blocks and scram signals from both instrument volumes. The inspector reviewed applicable surveillance test procedures and found that they adequately tested all installed instrumentation. The inspector also reviewed licensee design documents, as-built drawings and physical installation for susceptability to single failures; no single failure modes were identified.

-- Vent and Drain Valves

The inspector reviewed as-built drawings and physical installation and verified the following:

1. Vent and drain functions are not adversely affected by interfaces with other systems.

2. Vent and drain valves close on loss of instrument air.

3. Instrument volume vent and drain valves are redundant and do not appear to be suseptable to single failure.

4. Current Surveillance testing is adequate and meets the Technical Specification requirements.

-- Integrated Testing of the Entire System

The inspector reviewed facility surveillance tests to verify that all technical specification required testing is performed at the required periodicity and found no weaknesses in this area. The review revealed that the licensee currently performs no integrated scram testing and that the current Technical Specifications require no such test.

Based on the results of this review the inspector has determined that the licensee has met its long term commitments to upgrade the scram discharge volume. Temporary Instruction 2515/90 is closed.

4.0 Review of Plant Events (Modules 71707, 62703, 61726, 93702, 72701 and 37700)

The inspectors followed up on events occurring during the period to determine if licensee response was thorough and effective. Independent reviews of the events were conducted to verify the accuracy and completeness of licensee information.

a. Degraded Voltage Protection System Design Deficiency

During an engineering review the licensee identified that setpoints for safety-related degraded voltage sensing relays installed on the 4160 VAC emergency buses may not be adequate. The inplant electrical distribution system includes two safety-related 4160 VAC buses which in turn supply all lower voltage safety-related AC loads. The 4160 VAC buses are equipped with both loss of voltage and degraded voltage protective relays. Either set of relays will trip the bus feeder breakers and start the emergency diesel generators. The current Technical Specification setpoint for the degraded voltage relays is 3745 V with a 9.2 second time delay. If a transient occurred with the offsite power system already operating at a lower than normal voltage, the resulting turbine trip could cause further degradation of the offsite distribution system supplying the station. In this case, the degraded voltage relay setpoint may not be sufficient to ensure that the supply voltage to some 480 VAC equipment would be maintained within its design operating band. This deficiency was caused by a nonconservative assumption made during the licensee's degraded voltage analysis. The licensee reported this condition to the NRC via ENS at 6:00 p.m. on January 30, 1988. An NRC Special Electrical Team Inspection arrived onsite February 1, 1988 to perform a previously scheduled inspection of the licensee's onsite power distribution system. This team reviewed the degraded voltage protection problem. Licensee followup actions will be evaluated under an unresolved item as described in Electrical Team Inspection Report No. 50-293/88-08.

b. Engineered Safety Feature Actuations During a Computer Point Tie-in

On February 2, 1988, at 11:15 a.m., the licensee received unexpected isolations of the reactor water cleanup (RWCU) system and secondary containment, and an auto-start of the "A" standby gas treatment system. A shutdown cooling (SDC) isolation signal was also generated, however the SDC isolation valves were already closed, so that no further equipment actuation occurred. The actuations occurred when I&C technicians lifted leads in the isolation logic to allow tie-in of a process computer monitoring loop. The leads were relanded, a blown fuse was replaced, and the isolations were cleared. The licensee subsequently reported the actuation to the NRC via ENS, and initiated an investigation of the incident.

The inspector attended a licensee event critique on February 2. Two licensee management representatives, two I&C technicians, and two of the cognizant engineers were present. The inspector also attended a followup critique on the morning of February 3. During the critiques, the licensee postulated that the actuations were caused when the technician lifting the leads inadvertently touched them to an adjacent terminal. This created a momentary fault, causing a blown power fuse in one circuit, and momentarily reducing the potential in other circuits low enough to allow various relays to deenergize. In order to validate this scenario the licensee decided to proceed by relifting the leads and looking for evidence of electrical arcing.

After the licensee had made this decision but before the licensee proceeded, the inspector reviewed applicable elementary and connection drawings, reviewed a statement prepared by the control room staff, and inspected the cabinet. The connection drawings show that a common ground circuit would be interrupted by breaking contact between the two lifted leads. Breaking the common ground would cause the observed actuations. The construction of the affected terminal board makes it unlikely that the technician would touch an adjacent terminal while lifting the leads. However, the location was difficult to reach and the technician could easily have touched the leads to the adjacent point while attempting to restore the circuit. This would explain the blown power fuse. The technician stated that he experienced difficulty in relanding the leads. The inspector reviewed the instructions contained in Plant Design Change (PDC) 83-51D which controlled the work. Signal cut-in sheet 83-51D-150, ISO 726, constituted the specific instructions for control, implementation and testing of the activity. It stated only that a single RWCU valve would close and that the test capability for one main steam isolation valve would be lost. The signal cut-in sheet was inadequate in that the existence of the common ground loop and the impact of breaking it during the performance of the cut-in was neither recognized nor compensated for.

The above information was discussed with the licensee prior to implementation of the instructions to relift the leads. The inspector pointed out that relifting the leads would likely cause a second group of ESF actuations. The licensee evaluated the inspector's concern, concurred in the assessment and immediately took action to stop all ongoing tasks which could result in similar actuations, pending more thorough reviews.

The inspector informed the licensee that failure to perform adequate technical review and to establish adequate instructions for PDC implementation is an apparent violation of Technical Specification 6.8.A (VIO 88-07-01). Further, licensee technical follow-up of the ESF actuations was inadequate in that the cause of the actuations was not identified by the licensee until prompted by the inspector. The inspector also noted that no representative of the Technical Engineering Section was involved in the post-incident followup.

c. Secondary Containment Isolation Caused by a Failed Relay Coil

On February 2, 1988, at 7:08 p.m., an automatic start of the "A" standby gas treatment system, and isolation of the secondary containment occurred. Licensee investigation identified a failed electrical relay coil as the source. A circuit fault created by the failed coil resulted in a blown logic power supply fuse. Deenergization of the logic caused the observed equipment actuations. The relay and fuse were replaced, and the logic was reset. The NRC was informed of the actuations via ENS at 7:50 p.m. The failed relay was a General Electric Type CR120A. This type of relay has experienced a high failure rate at Pilgrim. The licensee is currently implementing a replacement program to address this problem. NRC followup is being conducted under existing inspector follow item 86-37-02.

d. Anticipated Transient Without Scram System Actuation

On February 3, 1988, at 7:36 p.m., the licensee received a spurious Division II anticipated transient without scram (ATWS) trip signal. The ATWS system normally would function to mitigate certain plant transients by tripping the reactor recirculation pumps and the alternate rod insertion (ARI) system at a reactor pressure of 1175 psig or reactor water level of -48 inches. In addition, the reactor feed water pumps are tripped at a reactor pressure of 1400 psig. When the spurious trip signal was received, both operating reactor recirculation pumps tripped, and the ARI system actuated, which depressurized the scram pilot valve air header allowing the scram valves to open. This resulted in water accumulation in the scram discharge instrument volume (SDIV) and a full reactor scram on SDIV high level. The licensee determined that no reactor feed pump trip signal was generated. The trip was cleared and the reactor scram was reset a short time later. The licensee reported the actuation to the NRC via ENS at 8:30 p.m. on February 3.

Event followup determined that the Division I ATWS system was not fully functional at the time of the trip due to ongoing modification activities. The licensee formed a task force led by the engineering department and composed of representatives from operations, maintenance, systems engineering and modifications management sections. A temporary procedure was approved to control investigation and troubleshooting. The inspector attended the licensee's event critique and observed that management appeared to effectively focus attention on development of a program for determining the root cause of this event. The resident inspectors will continue to follow licensee actions.

e. Unusual Event Due to a Fire in the Machine Shop

On February 11, 1988, at 7:35 p.m., the control room received a report of a fire in a contaminated area of the machine shop. The station fire brigade was dispatched to the scene. The Plymouth Fire Department was notified at 7:36 p.m. and three fire trucks arrived at the site by 7:50 p.m. An Unusual Event was declared at 7:50 p.m. The licensee's emergency plan requires declaration of an Unusual Event if there is a fire in a process building that is not controlled within 10 minutes after the fire fighting efforts have begun. This declaration is only required with reactor coolant temperature greater than 212 degrees F. The licensee's decision to declare the Unusual Event was conservative in that the fire appeared to have remained under control throughout the event, and reactor coolant temperature was less than 100 degrees F. The fire was extinguished but was still smoldering by 7:52 p.m. The fire was confined to a small area and was identified as burning insulation from a heat-treating machine which was being used on a valve disk in the shop. The smoldering insulation was placed into a 55 gallon drum filled with water, and the Unusual Event was secured at 8:05 p.m. Licensee radiological surveys indicated that there was no spread of contamination in the general area. Air samples taken in the area during the fire showed no airborne contamination. An NRC inspector was onsite at the time of the event and the resident inspectors performed additional followup, including observation of the licensee's post-incident critique. The inspectors noted that the critique was well-run and appeared to be very thorough and effective. Results of the resident inspector's followup were discussed with NRC Region I emergency preparedness specialist inspectors. On February 23 and 24, 1988, an emergency preparedness inspector was onsite to conduct additional incident followup. This review will be documented in inspection report 50-293/88-09.

f. Secondary Containment Isolation During an Electrical Relay Replacement

On February 23, 1988, at 2:24 p.m., the licensee experienced an inadvertent isolation of all inboard secondary containment isolation dampers, automatic start of the "A" standby gas treatment train, and an isolation of the inboard residual heat removal system discharge to radwaste primary containment isolation valve. The observed actuations occurred during a primary containment isolation system relay coil replacement. Maintenance technicians removed a fuse to deenergize the relay and allow its removal. It appears that the licensee failed to fully identify the effect of deenergizing the circuit. The technicians reinserted the fuse and the actuations were cleared a short time later. The licensee notified the NRC via ENS at 2:55 p.m.

The inspector's review of the maintenance request work package (MR 88-54-3 and MR 88-54-7) and interviews with personnel involved indicated that the preplanning and work instructions were not adequate. Also, the communication between the maintenance technicians and the duty operations personnel appeared to be poor. The inspector noted that the maintenance requests as presented to the duty operations staff lacked the work description and information regarding components potentially affected. Thus, the operation's review of the maintenance requests prior to their release relied heavily on informal verbal communciations from the maintenance technicians.

The preplanning and work instructions for MR 88-54-3 did not specify installation of a jumper on the neutral port of the circuit prior to the relay coil replacement. The maintenance technician involved indicated that he identified the need for a jumper and installed one, based on a previous event where lifting a lead to the common neutral caused a series of unexpected ESF actuations. The jumper was subsequently documented on the tagging request. Inadequate preplanning and work instructions were the subjects of a violation as documented in the inspection report 50-293/87-50.

Licensee management informed the inspector at the end of the report period that a comprehensive investigation was initiated involving various disciplines in the nuclear organization to review the above event and other recent inadvertant ESF actuations. The objective of the investigation is to identify common root causes and to develop appropriate corrective actions. The inspectors will monitor the outcome of the investigation.

g. ENS Notification of Inoperable SDV Isolation Valves

On February 23, 1988, at about 10:00 a.m., the licensee identified two scram discharge volume (SDV) isolation valves which failed to close in the required time. SDV vent and drain valves are required by the Technical Specifications to close on an isolation signal within 30 seconds. SDV vent valve CV302-23A closed in 90 seconds and drain valve CV302-22A closed in 15 seconds. The average closing time for the remaining operable valves on the SDVs was about 9 seconds. IE Bulletin (IEB) 80-14, Degradation of BWR Scram Discharge Volume Capability, Item A.3, required licensee's to notify the NRC within 24 hours if the SDV vent and drain valves are not operable or are closed for more than one hour in any 24 hour period during operation. This reporting requirement was incorporated into licensee notification procedure 2.2.17. Procedure 2.2.17 requires the reporting of any inoperability of a SDV vent or drain valve. Upon identifying the existence of this procedural requirement on February 24, 1988 the Watch Engineer informed the NRC via ENS at 9:55 a.m. IE Bulletin 80-14 was issued prior to implementation of the extensive modifications to the SDV later required by the NRC. Although the licensee complied with the IEB 80-14 reporting stipulations, such reporting may no longer be needed. The licensee stated that a review would be performed to determine if the requirement could be removed.

During inspection 50-293/87-57 SDV vent valve CV302-23B failed to close on demand. The inspector expressed concern that the failure of the three valves in a relatively short time could indicate a generic problem. The licensee stated that the valves would be disassembled when replacement parts are available and that a thorough investigation of the failure mode would be conducted. The inspector will continue to monitor licensee followup in this area.

h. Spurious Reactor Water Cleanup Isolation

On February 26, 1988, at about 1:10 p.m., the licensee experienced a partial reactor water cleanup system (RWCU) isolation. The outboard containment isolation valve on the RWCU suction line was previously removed from service for maintenance and MOVATS testing. After completion of the testing, the valve was opened and the valve motor operator feeder breaker was closed. A containment isolation signal was present but was not recognized. This caused the valve to automatically close when the operator was reenergized. The unanticipated isolation was reported to the NRC via ENS.

During a series of electrical equipment walkdowns performed over the last several years, the licensee has identified a large number of improperly installed wire terminations, or damaged components such as cracked terminal boards. These discrepancies were analyzed by the licensee and those found to be unacceptable have been scheduled for rework. Maintenance Request (MR) 88-12-07 was one of the MRs issued to perform this work. A portion of the isolation in preparation for performance of the activity was the removal of fuse 16A-K63A. Removing the fuse deenergized the non-regenerative heat exchanger high temperature trip and created a containment isolation signal. The trip has no direct annunciation. Initially, the licensee believed that this solation signal was not reset and remained unrecognized until the MOV was reenergized and automatically closed. Subsequently, the licensee concluded that control room operators had properly reset the isolation signal generated during performance of MR 88-12-07. The licensee now believes, that a routine start of a residual heat removal pump caused spurious RWCU high flow sensor oscillations and lead to the isolation. The spurious tripping of these sensors is the subject of existing Unresolved Item 87-50-06. As noted in Section 4.f of this report, the licensee initiated a systematic assessment of recent ESF actuations caused by maintenance activities.

It was noted in report 50-293/87-50 that the licensee's corrective maintenance program did not appear to provide for an effective method of documenting lifted leads and jumpers, and preparing detailed work instructions. In implementing MR 88-12-07, the licensee utilized Temporary Procedure (TP) 87-83, Attachment A, to control the lifted leads. While this TP was not written explicitly for this use the attachment is suitable for the application. A "Control Panel Isolation Instructional Termination Checklist" was utilized by the maintenance personnel performing MR 88-12-07. This checklist, along with its attachments, provided a good outline of work to be performed and its effect on the plant. This checklist, however, is not an approved part of the maintenance program, is not used with all MRs, and does not prescribe necessary restoration or post-work testing. In addition, discussions with the operations and maintenance staff indicate that this checklist is not included with the maintenance package and is therefore not reviewed by the operators. The operators appear to rely heavily on verbal communication with the maintenance technicians. Since no steps for restoration or post-work functional testing were included with the MR, the isolation signal could easily have gone undetected. Violation 87-50-07, the secondary containment isolation during replacement of an electrical relay described in Section 4.f of this report, and the above incident appear similar in that the preparation, implementation and restoration from corrective maintenance activities appears to be weak. Some steps such as use of TP 87-83 for lifted lead control and the use in some cases of a more detailed work checklist have been implemented and represent improvement. Additional attention to this area however, appears warranted.

The inspector also noted that many MRs associated with the repair of electrical terminations described above are checked, no retest required. The licensee has already completed most of the logic testing for the outage. This project requires the lifting of a large number of leads. The inspector questioned the acceptability of the decision not to retest. The licensee stated that an evaluation would be performed. This item remains unresolved pending licensee response (50-293/88-07-02).

i. Missed Technical Specification Surveillance Identified During a QA Audit

On March 4, 1988, during a Quality Assurance audit, the licensee identified that a once per cycle surveillance test of the "B" emergency diesel generator (EDG) may not have been performed as required during the last cycle. Pilgrim Technical Specifications require that each EDG be started and loaded once per cycle with the control circuits isolated from the cable spreading room to demonstrate remote shutdown capability. No record of performance of the surveillance per Procedure 8.9.13, Diesel Test From the Alternate Shutdown Panel, for the "B" EDG during the last operating cycle could be found. The test records were available for "A" EDG testing. The surveillance Procedure 8.9.13 is included in the Station Master Surveillance Tracking Program. In January 1987, both "A" and "B" EDG's were started and loaded locally following 10 CFR 50, Appendix R modifications. Performance of Procedure 8.9.13 for both EDGs is scheduled prior to restart.

5.0 Review of Licensee Overtime Control (Module 71707)

In September 1987, the NRC received an anonymous allegation that individuals at Pilgrim were working excessive overtime, and that plant management was allowing blanket overtime authorization.

The NRC established overtime guidelines for use by licensees in controlling and approving the use of personnel overtime. The guidelines are described in NUREG-0737, Generic Letter 82-12 and Generic Letter 83-14. The NRC policy outlined in these documents is that the use of overtime for personnel performing safety-related activities should be closely controlled. The routine use of overtime to compensate for staffing deficiencies should be discouraged. Various numeric overtime limits were established. It is recognized that under unusual circumstances these limits may be exceeded. In this case deviations should be authorized by the Plant Manager or his deputy, considering the possible affect on personnel performance which could result.

Previous NRC inspections in this area identified significant weaknesses. Notice of Violation (NOV) 85-26-05 concerned a failure to control licensed operator overtime. Unresolved (UNR) item 86-25-08 identified poor control of security force overtime. In response to these items the licensee significantly increased operator staffing, reduced the security force work load, and implemented a sixty hour work week limit for all personnel. This sixty hour limit is in addition to acceptance of the NRC guidelines, which have been incorporated into a station procedure.

In early October 1987, the NRC requested that the licensee evaluate its overtime control program and provide a written response detailing the results of that evaluation. The licensee's audit was concluded in October 1987 and by letter dated October 28, 1987 Boston Edison stated that station overtime was being properly controlled. This conclusion was based on a review of overtime records for the period of August 30, 1987 through October 3, 1987.

During the current inspection, NRC conducted an independent review of Boston Edison's overtime control program and implementation of that program. During this inspection, a regional based NRC inspector reviewed the licensee's program to determine if the NRC guidelines are adequately addressed and a review of licensee overtime records was conducted to determine the adequacy of program implementation. This review focused on maintenance personnel overtime, since routine reviews by the resident inspectors and security specialists have indicated that overtime controls in the operations and security areas have been improved.

Review of the licensee's policy and approved procedures indicates that appropriate overtime limits have been incorporated. The licensee's practice of limiting individuals to a sixty hour work week is conservative. In order to exceed established limits, Plant Manager approval is appropriately required. The inspector concluded that the licensee's program as currently described is adequate.

To determine if the program has been effectively implemented the inspector reviewed internal licensee memoranda regarding utilization of overtime in the maintenance department for the period of August 16 through October 3, 1987. In memoranda from a licensee staff engineer to the Plant Manager dated October 3 and October 14, 1987, it was identified that only 70% of persons exceeding the overtime limits had authorizations signed and on file. These reports also identified an uptrend in both the number of overtime exceptions granted and the number of hours worked. The inspector also reviewed time sheets for the months of January 1988 and found instances of personnel exceeding the overtime guidelines without the required Plant Manager approval. Unfortunately, both the records initially reviewed by the inspector and those used by a licensee engineer were payroll records, which can be in excess of actual work hours worked due to certain labor contract and pay clauses. Apparently, some supervisors are using information from the security computer that will indicate the time during which a worker is logged into the security computer. These records would appear to more indicative of actual hours worked than pay records, however, any periods of work assignment outside the security area would not be included. The security computer records were not provided until late in the inspection. Lack of clear and auditable records that unambiguously reflect the status of overtime use is itself an area of concern. Also, while overtime authorization records were generally available for maintenance personnel working hours in excess of the NRC guidelines, it is apparent that the approval process was not always complete prior to the work being performed. Specifically, supervisory approvals appeared to be before-the-fact, but senior plant management approvals were often after the overtime was performed. Also, from a review of the payroll records and a brief review of the later-provided security computer records, it was apparent that some of the same individuals were working overtime for several weeks in succession. The lack of pre-approval at the senior plant management level, as well as the prolonged approval of hours for maintenance personnel in excess of the NRC guidelines is not consistent with the intent of the NRC guidelines which discuss exceeding the guidelines only in unusual circumstances.

These observations were discussed with senior licensee management. In response, the licensee suspended the use of all significant overtime pending review of the situation. This action resolves the near term concern regarding controls on personnel overtime. Additional discussions were held between licensee management and NRC supervision to determine the licensee's evaluation of the overtime situation. The licensee indicated that it had been its policy since the management changes that occurred in early 1987, to very tightly control operator overtime, since excessive operator working hours could have a safety impact. More liberal overtime use for maintenance personnel was tolerated because of (1) the unusual circumstances created by the extended outage involving extensive plant upgrade work, and (2) management's judgement that, for a variety of reasons, the potential impact of extensive maintenance overtime was decreased productivity rather than decreased safety. Regarding pre-approval, the licensee had believed that pre-approval at the plant management level was not required by the NRC guidelines. Licensee management stated that they had believed that, despite the record-keeping lapses, supervisors knew and were controlling work hours, and workers were not overly fatigued. Plant management further stated that, although their review had indicated they met NRC guidelines regarding overtime, a series of memoranda had been issued to supervisors based on licensee management's own desire to reduce unnecessary overtime. NRC indicated to the licensee that, even though the inspectors have not identified any actual cases of excessive maintenance worker fatigue, the potential for such an impact underlies the NRC guidelines and forms part of the basis for guidelines specifying case-by-case approval of overtime above specified limits. Furthermore, although the guidelines do not clearly state that all levels of approval shall be completed before-the-fact, that is the intent. For example, the guidelines state that overtime authorizations shall have a paramount consideration that significant reductions in effectiveness would be unlikely. The licensee was receptive to NRC comments regarding the intent of NRC guidelines and indicated that it would submit an updated response to NRC's overtime concerns.

The inspector indicated to the licensee that the revised response should address, as a minimum, the following:

-- Measures for clear tracking of hours worked and for establishing easily auditable records;

-- Pre-authorization, at all specified levels of management, of instances of overtime in excess of the established guidelines; and,

-- Policy on use of overtime in excess of guidelines by the same individuals over an extended time period.

Final resolution of the licensee's corrective actions to ensure long term, effective controls are developed will remain unresolved pending future inspection (UNR 88-07-03). Based on the creation of UNR 88-07-03 and the results of routine NRC observations of the administrative controls being implemented to control licensed operator and security overtime NOV 85-26-05 and UNR 86-25-08 will be administratively closed. Formal resolution of all station overtime issues will be tracked under Unresolved Item 88-07-03.

6.0 <u>Technical Review of the Direct Torus Vent Modification</u> (Modules: 37700 and 37702)

a. <u>Background and Scope of Review</u>

On March 2-3, 1988, an NRR inspection team, composed of three members, conducted an onsite inspection of the modification to install a direct torus vent line. This design modification, described by PDC 86-51 and addressed in Safety Evaluations No. 2197, 2216 and 2269, provides a direct vent path from the torus air space to the main stack, bypassing the Standby Gas Treatment System (SGTS) equipment of the torus purge exhaust line. The direct torus vent line, an 8" line, connects to the existing torus purge exhaust line (penetration X-227) at the upstream end by a tee located between containment isolation valves AO-5042B and AO-5042A. Downstream, the direct torus vent line is connected to the 20-inch main stack line downstream of SGTS valves AON-108 and AON-112.

The installed configuration of the direct torus vent line currently includes a blind flange assembly in the line approximately 10 feet from the upstream connection and an in-line blank plate approximately 3 feet from the downsteam connection. Both of these barriers are rated for 150 psi. Originally the licensee proposed installation of an 8-inch automatic butterfly valve (AO-5025) and 30 psid rated rupture disc at the same locations when the blind flange and blank plate are now installed. By letter dated August 21, 1987, the NRC indicated to Boston Edison that such a modification could not properly be performed under the provisions of 10 CFR 50.59 due to the need for revised technical specifications to address the new automatic containment isolation valve (AO-5025). At that juncture the licensee proceeded with installation substituting a blind flange and blank plate for the originally proposed butterfly valve and rupture disc. In addition to the new piping, blind flange and blank plate, the installed modification replaces the AC solenoid valve for AO-5042B with an ASCO DC solenoid valve powered from essential 125 volt DC power supplies. Nitrogen lines were added to provide backup nitrogen to AO-5042B.

The objective of the NRR inspection was to evaluate the installed design configuration to assure the adequacy of the modification and its supporting safety evaluation. Because the installed modification leaves the direct torus vent line non-functional, i.e., the blind flange and blank plate isolate the piping, the team evaluated the modification to assure only that there is no adverse safety impact on the plant resulting from the installation of the new, albeit isolated, bypass line. In this regard the inspection focused on issues in the following three principal areas:

(1) Systems Issues:

-- Impact of the installed vent line and associated components on the containment isolation design.

-- Effects of the installed vent line on the operability of the SGTS.

(2) Mechanical Design Issue:

-- Evaluation of the modification with respect to the piping response to loading conditions, i.e., Mark I Program loads.

(3) Structural Design Issue:

-- The effect of the added vent line on the torus response to loading conditions.

b. Review of System Issues

With regard to the effect of the vent line on the containment isolation design, the modification potentially influences containment isolation due to: 1) the addition of a branch line off an existing penetration, connected between containment isolation valves and 2) modification of an existing containment isolation valve AO 5042B, replacing the AC solenoid with a DC solenoid and addition of a backup N2 supply to operate the valve.

The inspectors reviewed the design modification and concluded that applicable containment isolation requirements are satisfied. The need for an additional containment isolation barrier is satisfied by the blind flange assembly. The direct torus vent line is designed to ASME Section III Class 2 requirements from the upstream tee connection up to and including the blind flange assembly.

Containment leak testing has also been performed to verify the leak tight integrity of the design modification. The blind flange has been locally leak tested, and the piping section bounded by the isolation valves AO-5042 A&B and the blind flange has been tested to "Pa" (i.e., the calculated peak containment internal pressure related to the design basis accident). Furthermore, stroke testing was performed on the containment isolation valves.

The replacement of the AC solenoid valve with a DC solenoid has no adverse impact of the valve to perform its isolation function as demonstrated by functional testing.

With regard to the effects of the installed vent line on the operability of the SGTS, the inspectors considered the design features which provide for isolation of the vent line from the SGTS and concluded that redundant barriers provided by the blind flange and blank plate are adequate to assure operability of the SGTS.

c. Review of Mechanical Design Issues

The mechanical engineering staff reviewed samples of letters, drawings, and related documentation which contained information of loads, load combinations, design limits, and summaries of analysis results, and had the following findings.

The inspectors found that the analysis of this specific piping and supports did incorporate necessary loads, including thermal, seismic, and rupture disc dynamic loads. The design loads had also considered the effects of 27 possible event combinations from the previous modifications for the Mark I Long Term Program. The inspectors found the loads and load combinations acceptable.

The inspectors reviewed summaries of analysis performed by Bechtel and Teledyne. The analyses include cases before and after the installation of valve and rupture disc to the 8" direct vent line. Although both ANSI B31.1 and ASME Class 2 piping codes were applied in one pipe run, the analysis was performed using ASME Class 2 rules for the entire pipe; this is acceptable.

The inspectors noted that the level D stress limits were used for the direct torus vent line design under rupture disc dynamic condition. The staff believes that if the sole function of a piping system is to mitigate the consequences of a plant accident event, its design limits should be less than level D. Due to rather unique design consideration of the direct torus vent line at Pilgrim, the staff position on stress limits will be formed in near future. The licensee will investigate whether the line can meet lower level stress limits. This issue was reviewed for future consideration, because it involves only the currently isolated portions of the system, which was not a subject of this inspection.

The licensee was committed to meet IE Bulletin 79-02 requirements on expansion anchor bolts. A factor of 4 or 5 was used. The inspectors found that this is acceptable.

The inspectors found the pipe support design limits using the AISC Code acceptable.

In conclusion, the inspection found that the piping support design of the installed modification is acceptable.

d. Review of Structural Issues

The structural inspections covered effects of modification on the structural integrity of the torus itself and the design of pipe supports and the associated anchorage.

Correspondence between Teledyne Engineering Services (TES) and Boston Edison Co. (BECo) (6706-16) dated February 5, 1988 indicated that the subject modifications meet the ASME Code requirements of the 1977 Summer Editions for two cases: with valve AO-5025 in place or with the valve replaced by the 100 point blind flange assembly. The subject correspondence also provides the anchor load summary at the torus nozzle and at the supports.

From the review of the correspondence between TES and BECo (6706-16) dated January 14, 1988, it appears that the TES performed the analysis using the bounding events developed from 27 load combinations. This would indicate that the analysis was performed in accordance with the recommendations of NUREG-0661, "Safety Evaluation Report, Mark I Containment Long-Term Program" dated July 1980. The inspection team conducted a telephone conference jointly with the BECo staff, with the principal engineer of TES who confirmed that the modification analysis was performed in accordance with the requirements of the NUREG-0661, and NEDO-24583, "Mark I Containment Program Structural Acceptance Criteria Plant Unique Analysis Application Guide", Task No. 3.1.1, General Electric Topical Report, December 1978. These criteria are acceptable to the staff.

The inspection team was informed that the design of the anchors for the new line, as well as examination of the effects resulting therefrom, was performed by Bechtel Eastern Power Co. (Bechtel), and reviewed the notes dated February 2 and 3, 1988 documenting telephone conversation which would indicate that Bechtel completed the evaluation of the Direct Torus Vent (DTV) pipe supports using the loads provided by TES. The criteria used in this work were contained in the BECo Specification PDC 86-51, "Direct Torus Vent" Rev. 0, dated May 18, 1987. This specification states that the standard manufactured pipe support items were analyzed in accordance with the ASME B31.1 through winter 1980 addenda and the requirements of NRC I&E Bulletin 79-11. The custom-designed tube steel supports were designed in accordance with the Specifications contained in the "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings" effective November 1, 1987. These criteria are considered acceptable.

The inspection team reviewed the pertinent parts of the specification No. C-110-ERQ-EO, "Design of Pipe Supports for 2 1/2 Inches and Larger Piping" Rev. 0, dated March 16, 1985, which was one of the documents used by Bechtel in design. This specification states that anchor bolts should be designed with the factors of safety of 5 (Hilti sleeves type and Phillips snap-off-self drilling) and 4 (wedge type Hilti Kwik). The shear/tension interaction equation is based on the straight line with the actual (calculated tension load times two) if it is based on rigid plate assumption. This was found to be acceptable.

7.0 Management and Exit Meetings (Module: 30703)

At periodic intervals during the inspection period, meetings were held with senior facility management to discuss the inspection scope and preliminary findings of the resident inspectors. A final exit interview was held on March 18, 1988 to discuss findings with licensee management.

At no time during any of the above referenced meetings did the licensee identify the issues followed during this inspection as involving proprietary information.

Attachment I to Inspection Report 50-293/87-07

Persons Contacted

R. Bird, Senior Vice President - Nuclear
* K. Highfill, Station Director
R. Barrett, Plant Manager
E. Kraft, Plant Support Manager
R. Anderson, Planning and Outage Manager
D. Swanson, Nuclear Engineering Department Manager
J. Alexander, Operations Section Manager
N. Brosee, Maintenance Section Manager
J. Jens, Radiological Section Manager
N. Gannon, Chief Radiological Engineer
J. Seery, Technical Section Manager
P. Mastrangelo, Chief Operating Engineer
R. Sherry, Chief Maintenance Engineer
D. Long, Security Manager
F. Wozniak, Fire Protection Manager

*Senior licensee representative present at the exit meeting.