U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 87-09

Docket No. 50-352

License No. NPF-39

Licensee: Philadelphia Electric Company
2301 Market Street
Philadelphia, PA 19101

Facility: Limerick Generating Station, Unit 1

Inspection Period: March 19 - May 16, 1987

Inspectors: E. M. Kelly, Senior Resident Inspector
S. D. Kucharski, Resident Inspector

Approved by: James C Linville Jr — 6/18/87
James Linville, Chief, Projects Section 2A — Date

Summary: Routine daytime (265 hours) and backshift (25 hours including weekends) inspections of Unit 1 by the resident inspectors consisting of: followup on outstanding items and license conditions; walkdown of the HPCI system and the scram discharge volume using PRA guidance; plant tours including security and fire protection measures; maintenance and surveillance observations; evaluation of modifications and outage planning; and review of LERs and periodic reports. Operation under Amendment 3 to the Unit 1 License with increased core flow and decreased feedwater heating was verified to be procedurally followed. Also observed was the 24-hour control room coverage by the Nuclear Operations Monitoring Team instituted from April 10 to May 15.

Independent inspections were conducted that evaluated storage practices for temporary equipment throughout the plant; HFA relays in Class 1E circuits, HPCI turbine overspeed trip reliability; scram pilot solenoid valve air leakage; and practices related to planned manual scramming of the reactor. Several meetings were attended onsite during the period, including routine PORC; OEAC Meeting 87-04 on April 21; NRB Meeting No. 201 on April 9; an ANI exit on March 27; a Unit 2 preoperational test meeting on April 19, 1987; and Limitorque valve testing on May 5.

One violation was identified (discussed in Detail 3.3.2) regarding administrative control of combustible free zones. An unresolved item was initiated for security system test measures (Detail 3.2.2).

DETAILS

1.0 Principals Contacted

Philadelphia Electric Company

J. Doering, Superintendent of Operations
R. Dubiel, Senior Health Physicist
G. Edwards, Technical Engineer
J. Franz, Station Manager
G. Hunger, Nuclear Safety Section Head
J. Harding, Field Engineer
J. Law, Outage Planning
R. Moore, Superintendent, QA Division
J. Spencer, Superintendent of Services

Also during this inspection period, the inspectors discussed plant status and operations with other supervisors and engineers in the PECO, Bechtel and General Electric organizations.

2.0 Followup on Unresolved Items

2.1 (Closed) Construction Deficiency 84-00-10

The inspector reviewed the completion of modification 86-0136 in response to a license condition based on Significant Deficiency No. 146 reported to the NRC on September 5, 1984.

Modification 86-0136 provided diesel oil storage tank valve pit back-flood protection. The modification installed check valves on the drains from the individual cells on top of the diesel fuel oil storage tanks to prevent back-flooding from the common oil separator unit (into which the drains from all eight diesel storage tank valve pits connect). The modification eliminated the possibility of a single failure resulting in the flooding of more than one diesel storage tank, resulting in the possibility of rendering diesels inoperable without control room annunciation.

The modification also raised the elevation of the underground fuel oil tank vacuum relief valve by 13-inches as a precaution to prevent water accumulating in the pits from entering the tanks, as previously experienced.

The inspector reviewed the MDCP 86-0136 package with Construction engineers and QA representatives, observed the completed modification work, and concluded that the licensee had met the commitments associated with license condition.

2.2 (Closed) IE Bulletin 86-03

The inspector reviewed the licensee's response dated November 13, 1986 to NRC IE Bulletin 86-03 concerning a loss of minimum flow bypass capability for all ECCS pumps due to a single failure. The inspector discussed the response with responsible test engineers and agreed with the licensee's conclusion that a single-failure vulnerability in ECCS minimum flow recirculation lines at Limerick did not exist. The bases for the conclusion is that all minimum flow line shutoffs employ motor-operated valves (not air-operated) and an AC electrical safeguard division failure is enveloped by the loss of a diesel generator and its associated 4kV bus which is within the Limerick design basis. No further concerns were identified, and Bulletin 86-03 is closed.

2.3 (Closed) License Condition 2.C.(3)d.

The subject License Condition required a stairway to be installed for the fire brigade's access from the Turbine Enclosure elevation 239 to the Unit 1 cable spreading room via the Unit 2 cable spreading room prior to startup from the first refueling outage.

The inspector verified the completion of modification 491 which installed a permanent stairwell for improved fire brigade access to the cable spreading rooms. QA surveillance report 1C-300 was performed on October 8, 1986 to verify the stairwell compeltion. The inspector independently walked down the complete stairway and identified several concerns regarding the effectiveness of the modification. In response, the licensee performed a fire drill on April 30, 1987 and documented the results of the drill in a May 1, 1987 memorandum. The following conclusions were reached:

- The present scaffold configuration located on the stairway does not hinder a firefighter in full protective gear from advancing a hose line and accessing the Unit 2 inverter room.

- The firefighters experienced no problems entering the room with a hand line while a portable air blower and duct was in the doorway.

- A sign which identifies the location of the card reader has been affixed to the wall adjacent to the card reader.

- A sign which identifies this stairway as an emergency access to and from Unit 2 inverter room (and not to block it with scaffold or material) has been affixed to the stairway support steel.

The licensee agreed to perform additional fire drills during the current drill quarter requiring the fire brigade to access the Unit 2 static inverter room via the subject stairway. At that time, any changes in scaffold configuration or access problems will be noted by the drill instructor so that corrective action can be taken. The inspector concluded that the above actions were responsive to his concerns, and considered the licensee to be in compliance with License Condition 2.C(3)d.

2.4 Part 21 Report

On March 16, 1987, the licensee issued a Part 21 Report describing errors introduced in P&IDs and QA drawings (QADs) by a conversion from manually drafted drawings to a Computer Aided Design and Drafting (CADD) system. A total of 184 drawing sheets for Unit 1 and common were potentially affected, and a total of 1131 errors were identified. A complete re-check of all CADD generated P&IDs was completed, corrections were made, drawings were re-issued and drawings were in-place at Category 1 drawing locations in March 1987. The drawing errors were described in a meeting held onsite with NRC representatives on March 13, 1987. The root cause and characterization of the errors were addressed in NRC Inspection Report 50-352/87-05.

The inspectors assessed the corrective actions described in the licensee's Part 21 Report by periodically sampling P&IDs in the main control room and other Category 1 locations. No additional errors were identified. The licensee also reviewed subtier documents which may have been revised or prepared based on the P&IDs which contained errors during the time frame of July to December 1986. The documents included procedures, blocking sequences, modification packages, procurement documents and maintenance performed on safety-related equipment. No discrepancies were identified which affected safety-related equipment. Also, based on a PORC assessment of the drawing errors, the licensee's independent safety engineering group (ISEG) performed a review on March 19 and 20 of Welder Information Data (WID) sheets to determine if there existed errors caused by the conversion of Limerick Generating Station Piping and Instrumentation Drawings to a CADD system. The review focused on identifying WID sheets which involved systems for which a request for drawing change had been written to correct a P&ID-to-CADD conversion error. The review was limited to piping line classification type errors. Ninety WID sheets were reviewed and no discrepancies were discovered. As a result of this review the ISEG concluded that the impact on Unit 1 welding has been minimal and no significant safety concerns exist.

The inspectors discussed the above actions with ISEG representatives and expressed no further concerns with respect to the effect of the drawing errors on Unit 1 operation. Resolution of the licensee's QA organization's findings are being followed as part of item 50-352/87-05-02.

3.0 Review of Plant Operations

3.1 Summary of Events

Limerick Unit 1 began the period operating at 95% power, and 105% core flow with partial feedwater heating. This method of operation was approved by the NRC in License Amendment No. 3 issued on February 18, 1987 as previously discussed in Inspection Report 50-352/87-05. The plant continued end-of-cycle coastdown operations to 76% power until May 15 when it was shut down for the first refueling outage.

3.2 Operational Safety Verification

3.2.1 Control Room Activities

The inspectors toured the control room daily to verify proper manning, access control, adherence to approved procedures and compliance with technical specifications. The inspectors reviewed shift superintendent, control room supervision, licensed operator, and Nuclear Operations Monitoring Team (begun on April 10) logs and records covering the entire inspection period. The inspectors performed backshift and weekend tours of the facility on the following days: March 27, 30, 31; April 11, 12, 13, 25 and 30. On March 27, April 13 and April 30 the backshift inspections were between the hours of 2:00 a.m. and 6:00 a.m.

The inspectors reviewed logs and records for accuracy, completeness, abnormal conditions, and significant operating changes and trends. Other logs and records reviewed included: Reactor Engineering STA Book, Night Orders, Radiation Work Permits, Locked Valve Log, Maintenance Request Forms, Temporary Circuit Alterations, and Ignition Source Control Checklists. Control Room logs were compared with Administrative Procedure A-7, Shift Operations. Frequent initialing of entries by licensed operators, shift supervision, and licensee site management constituted evidence of licensee review. No unacceptable conditions were identified.

Instrumentation and recorder traces were observed, and the status of control room annunciators was reviewed. Nuclear instrument panels and other reactor protective systems were examined. Effluent monitors were reviewed for indications of abnormal releases; none were evident. Panel indications for onsite/offsite emergency power sources were verified for automatic operability.

Sampling reviews were made of equipment trouble tags (ETT's), shift night orders, and the temporary circuit alteration (TCA) and LCO tracking logs. The inspectors also observed shift turnovers during the period. Operations activities were observed for conformance with Administrative Procedure A-7; no unacceptable conditions were noted.

3.2.2 Security

During entry to and egress from the Unit 1 Protected Area and vital areas, the inspector observed access control, security boundary integrity, search activities, escorting and badging in accordance with Security Plan implementing procedures and guard force instructions. The inspector also observed the availability and operability of Security Systems Equipment.

The inspector noted during the performance of ST-7-084-311-0, Daily Security System Equipment - Operational Test of X-Ray, Metal Detection and Explosive Detectors, Revision 6, that the security force member (SFM) placed an unconcealed object onto the x-ray machine to challenge the operator. When questioned by the inspector the SFM agreed that the object should be concealed. Security personnel agreed that the procedure should be changed to challenge the operator with a concealed object. Also noted by the inspector in ST-7-084-932-0, Security System Equipment Performance Test of Metal Detectors, was that if a problem occurs, there is no corrective action to be taken in the procedure. Security personnel stated that the procedure would be corrected. These items will be unresolved until corrections are made in the procedures and reviewed in future inspection (50-352/87-09-01).

The inspector verified that the licensee's controls for access at the North Gate of all vehicles to the protected and vital areas were in accordance with the physical security plan and regulatory requirements. Vehicle inspections and required vehicle escorting were observed on a number of occasions to be in accordance with security procedure PP-019 and Post Orders Nos. 7 and 8 for vehicle search and access control. The designated vehicle authorization list was reviewed and discussions were held with security force members and station security staff.

No violations were identified.

3.2.3 Radiological Controls

The inspectors observed the availability of radiation monitoring equipment, including portal monitors and portable friskers. In the past, the licensee had several problems with workers disabling the portal monitors by piercing them with protruding objects. The licensee has now placed observers in the area of the monitors to eliminate the problem by surveilling the workers. No unacceptable conditions were noted.

3.2.4 Fuel Integrity

Primary coolant and offgas radiochemistry parameters were reviewed by the inspector and discussed with licensee representatives from Reactor Engineering Chemistry. The licensee performs procedure RT-3-097-640-1, Fuel Integrity Monitoring, daily to monitor gross iodine levels in reactor water and the calculated sum of six noble gas activities at the recombiner aftercondenser discharge. The offgas pretreatment summation of 6 noble gas activities is 252 uCi/sec with an offgas system flow of 30 scfm. Gross iodine levels in reactor water were 15.6 x 10E(-4) uci/cc. The comparable Technical Specification limits are approximately three orders of magnitude greater. The inspector also discussed the results of procedure RT-5-000-802-1, Fission Product Distribution, last performed on April 16, 1987. The results indicated a recoil distribution caused by tramp uranium. The inspector concluded that all data indicates that there is no fuel degradation. No other further concerns were noted.

3.3 Station Tours

The inspectors found accessible areas of the plant throughout the inspection period, including: the Unit 1 reactor and turbine-auxiliary enclosure, the main control and auxiliary equipment rooms; battery, emergency switchgear and cable spreading rooms; and the plant site perimeter. During these tours, observations were made of equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping, tagging of equipment, ongoing maintenance and surveillance, and the availability of redundant equipment.

3.3.1 Transient Equipment Storage

The inspector reviewed and toured the plant for storage of transient material and equipment in safety related areas. This concern was presented to the industry on May 16, 1980 in IE Information Notice No. 80-21 - Anchorage and Support of Safety-Related Electrical Equipment. The licensee internally responded to this concern on August 5, 1980. The licensee has also developed guidelines to support their administrative procedures in these areas. When touring the plant, which is in a refueling outage, the inspector had several minor concerns which dealt mostly with storage boxes not being firmly secured. This was brought to the attention of the licensee, who responded immediately by either removing the boxes or pinning the wheels so they could not roll. All other equipment such as scaffolds, welding equipment, and bottles were tagged and secured properly and in accordance with procedures. The inspector had no further questions.

3.3.2 Combustible Free Zones

During a tour of the Reactor Enclosure on elevation 217, the inspector observed numerous combustible items, equivalent to two bags of trash, stored unattended in a combustible free zone in Area 15 on May 12, 1987 inside of a CRD decontamination facility being erected to support outage work.

Combustible materials found unattended consisted of a small amount of trash (i.e. plastic bags and paper towels). However, because of the hourly fire watch established for the fire zone to compensate for the construction of the temporary CRD repair facility, the inspector expressed a concern for the effectiveness of the fire watch in that the combustible materials found on May 12, 1987 had not been questioned or removed. The control of transient combustibles in combustible free zones had been the subject of a previous unresolved inspection finding (50-352/86-09-01). This was identified as a violation of Administrative Procedure A-12.2, Control of Combustible Materials (50-352/87-09-02).

The temporary structure was being erected under Modification 86-5145 to support outage repairs planned for approximately 20 CRD assemblies. The permanent CRD repair area is located in Unit 2 and will not be available for use during the Unit 1 refueling outages that occur during Unit 2 construction. The temporary CRD repair area consists of a stainless steel modular enclosure and is intended for use while the reactor is in cold shutdown, and will be removed before reactor startup.

The temporary facility was being surveilled as part of an hourly firewatch at the time the combustible items were discovered. The facility was partially complete, and scaffold had been erected to complete the structure composed of 12 ft. high x 12 ft. wide x 50 ft. long steel.

The inspector reviewed the safety evaluation associated with modification 5145 addressing the impact of the temporary facility on plant fire protection systems and the effect in the combustible free zone. A meeting with corporate fire protection representatives and plant staff was scheduled for the week of May 18 and the acceptability of the facility will be addressed in Inspection Report 50-352/87-13.

3.4 System Walkdowns

3.4.1 Engineered Safeguards Features Verification

The inspector independently verified the operability of the High Pressure Coolant Injection (HPCI) system by performing a detailed walkdown of the accessible portions of the system, and confirmation of the following items:

-- Review of Emergency Core Cooling Systems (HPCI) related Technical Specifications, FSAR, System Operating Procedures and P&IDs.

-- Identification of equipment conditions and items that might degrade performance.

-- System check-off list S55.1.A (COL) Equipment Alignment for Automatic Operations of HPCI System, Revision 4, and operating procedures consistent with plant drawings.

-- Valves and breakers were properly aligned, including appropriate locking devices.

-- Instrumentation properly valved in and functional.

-- Control room switches, indications, and controls are satisfactory.

-- Surveillance procedures adequately implement Technical Specification requirement.

Within the scope of the inspection, no unacceptable conditions were noted.

3.4.2 PRA-Based System Inspection

The inspector performed selected system walkdowns utilizing methods prescribed in a study prepared for the NRC by Brookhaven National Laboratory using the Limerick Probabilistic Risk Assessment (PRA). The study entitled PRA-Based System Inspection Plan dated May 1986, provides inspection guidance by prioritizing plant safety systems with respect to their importance to risk. The study contains an abbreviated version of the licensee's system checklists which contain components that are considered to have a high risk factor as determined by the PRA.

The inspector verified that no abnormal alarms were present and the proper configuration of the following HPCI and RHR low pressure injection (LPCI) system components on several occasions during the inspection period:

-- HPCI inboard and outboard steam supply isolation valves HV-55-1F002 and 3, open

-- CST supply to ECCS, valves HV-55-124 and 125, open

-- HPCI pump suction from CST, HV-55-1F004, open

-- HPCI pump discharge, valve HV-55-1F007, open

-- ESW inlet and outlet valves 11-1022 and 1024 for HPCI room cooler, open

-- HPCI turbine exhaust stop check valve, 55-1F021, locked open

-- Core Spray Loop B manual injection valve 52-1F007B, locked open

-- RHR heat exchanger Service Water, inlet valves HV-51-1F014A and B, energized, closed and handswitch in auto.

-- RHR heat exchanger Service Water, outlet valves HV-51-1F068A and B, energized, closed and handswitch in auto.

-- RHR heat exchanger Service Water, bypass valve HV-C-51-1F048B open

-- LPCI injection valves HV-51-1F017A, B, C and D; energized, closed and in auto.

No unacceptable conditions were noted.

3.5 Meetings Onsite

3.5.1 Limitorque Hydraulic Lockup

A meeting was held on May 5, 1987 between the licensee and the NRC headquarters personnel in which the licensee presented their experience with Limitorque hydraulic locking and their rework program. This meeting was requested by the NRC because of a recent AEOD engineering evaluation report on operational data involving motor operated valve (MOV) failure due to hydraulic lockup from excessive grease in the spring pack area of the motor operator.

The licensee's initial occurrence with hydraulic lockup was during the operation of a containment atmosphere control valve HV-057-105 during preoperational testing in 1983. The initial indication of a valve problem was motor thermal overload trip. Upon inspection, grease was found filling the spring cartridge cavity. The grease was removed and the valve was retested. After 12 to 15 strokes the overload trip occurred again. The spring cartridge cap was again filled with grease. The grease was being trapped in the spring cartridge cap and could not pass between the torque limiting sleeve and the spring cartridge cap to get back to the relief point. The licensee fabricated a slotted torque limiting sleeve and stroked the valve numerous times with the new sleeve without stalling. The sleeve modification was approved by Limitorque and no further problems occurred. The licensee had also experienced hydraulic lockup during MOVATs testing. In some cases a motor stall occurred, in others the time rate of spring compression decreased. In each case the torque limiting sleeve was slotted and verified to eliminate the problem. The licensee reinstalled the original torque limiting sleeve and the operator stalled, which verified the effectiveness of the repair. The inspector had no further questions.

3.5.2 Pre-Operation and Start-Up Test Program Unit 2

On April 21, 1987 a meeting was held at the Limerick Generating Station training center to discuss the Limerick Unit 2 Pre-Operational and Start-Up Test Program. Several representatives from PECO and Bechtel Power Corporation presented the following:

-- Test Program Administration and Organization

-- Construction Testing including Blue Tag Tests

-- Start-Up Testing including Technical and Pre-Operational Tests

-- Test Review Board

-- QA/QC Program

-- Operator Staffing and Responsibilities

-- Start-Up Test Schedule

One of the concerns during the meeting was the impact on Unit 1 during Pre-Op and Start-Up Testing. The licensee's plan at the present time is to utilize Unit 1 personnel to perform testing for Unit 2. The inspectors will review the matter further during subsequent inspections.

3.6 Refueling Outage Preparations

3.6.1 Work Planning

The inspectors met with licensee outage planning engineers on several occasions during the inspection period to discuss planning for the first refueling outage scheduled to begin on May 15, 1987. The length of the outage is 77 days, allowing for 7 days at the conclusion for post-maintenance and modification testing including tie-in of the SGTS to the refueling floor zone (see Detail 8.1).

There are approximately 91 modifications to be completed during the outage, and 41 of those modifications involve pre-fabrication work prior to the outage. A total of 707 corrective maintenance activities and 721 preventative maintenance actions are planned to be worked. A full core offload is planned, and other core alterations will include replacement of 15 LPRMs and rebuilding of 20 CRDs. A total of 540 I&C surveillance tests are scheduled, and 187 LLRTs. A containment ILRT is expected to commence during the week of July 13th. Plans are to startup and synchronize to the grid by July 31.

3.6.2 Operations Under License Amendment No. 3

The inspectors verified adherence to administrative controls established to implement License Amendment No. 3. This amendment provided for increased reactor core cooling water flow rates up to 105% of rated and a reduction in feedwater heating to extend the fuel cycle. The amendment also deleted License Condition 2.C(13) which prohibited operation with partial feedwater heating for the purpose of extending the normal fuel cycle.

The value of core minimum critical power ratio (MCPR) was increased from 1.22 at rated conditions to 1.24. The increased MCPR applies at maximum core flow and at up to 60°F reduction in feedwater temperature, a result of the change in the limiting transient (a run-away feedwater pump). The change in MCPR was incorporated in the revised Technical Specifications for use when the plant is operated in the extended flow/temperature condition. The value of MCPR was also changed in the plant process computer.

Another related change to the Technical Specifications involved the addition of a high flow clamp on the rod block monitor. Formerly, the clamp was unnecessary because of the 100% flow limit. Procedures for instituting a high flow clamp along with the procedures for changing the flow comparator rod block setpoints were established and reviewed by the inspectors.

Two special procedures, SP-S-049 and 050, were developed that integrated the requirements necessary to enter the extended flow conditions. General Procedure (GP)-5, Power Operations, was revised to incorporate guidelines and instruct operators regarding power maneuvers in the extended flow condition. The inspectors verified that reactor operation was maintained within the analyzed range of feedwater inlet temperature and core thermal power depicted in a figure attached to GP-5.

A change was also made to GP-5 to allow maintaining reactor steam dome pressure at 1020 psia using the turbine EHC pressure set. Because power at the end-of-cyle coastdown was at 88% thermal power, steam dome pressure had fallen to 1005 psia. At 100% thermal power, steam dome pressure is normally 1020 psia. Increasing reactor pressure increased reactor power due to decrease in core steam voids, and increased plant efficiency. General Electric Nuclear Engineering representatives were consulted and advised the licensee that 1020 psia is the pressure used in the Nuclear Design Report Analysis, and any operation at or up to 1020 psia is acceptable. The inspector discussed the increase in pressure set with plant management, attended several PORC meetings during the inspection period at which the pressure increase was addressed, and had no identified concerns.

Reactor operations throughout the inspection period were periodically determined to be below 105% core flow and in accordance with License Amendment No. 3. No violations were identified.

3.6.3 Anticipated Operations During Shutdown

The licensee developed a new procedure GP-6.2, retitled Shutdown Operations, to supplement existing procedural guidance and to address four of the most impacting Technical Specification requirements encountered in the shutdown condition; namely, establishing (1) alternate shutdown cooling, (2) alternate reactor cooling recirculation, (3) suspending operations with the potential for draining the vessel, and (4) establishing secondary containment integrity. The inspector discussed the guidance contained in GP-6.2 with operations supervisors and licensed operators. The inspector found all personnel to be knowledgeable and concluded that the new GP-6.2 was indicative of well-conceived and thoroughly planned outage preparations. The inspector identified no concerns.

3.6.4 Planned Shutdown to Begin Outage

Containment de-inerting was performed and a controlled shutdown was begun on May 15 from 76% power. A manual scram was initiated two hours later from 25.5% power by placing the mode switch to the shutdown position. The inspector observed the scram and verified appropriate plant equipment response. Licensed operators followed appropriate T-100 emergency procedures; a post-scram review utilizing GP-18 was appropriately conducted; and an independent review of the plant computer sequence-of-events log indicated satisfactory RPS performance. Station management was present in the main control room immediately prior to and following the scram evolution. The inspector identified no concerns.

4.0 Onsite Followup of Events

The inspector performed onsite followup of the following events that occurred during the inspection period. The events were evaluated for proper notification of the NRC, reactor safety significance, licensee efforts to identify cause and propose effective corrective action, and verification of proper system design response.

4.1 Diesel Generator Relay Failure

A local alarm indicating a diode failure in the generator field flashing circuit was received shortly after the monthly operability test for the D14 emergency diesel engine was begun on May 5, 1987. The generator field continued to be flashed and never automatically transferred to the self-excitation phase, nor was the output breaker closed onto the bus. The engine was shutdown after 20 minutes of operation, and was declared inoperable. Offsite electrical power sources were verified as available, and the remaining three diesel engines started and operated to assure operability.

Licensee field engineering investigation found loose power cables to two of the three main contacts of a relay in the D14 generator field flashing logic, preventing self-excitation of the generator and hence continued diesel-genrator operation. Two of the 3 cables to the "K1" relay, a 200-amp latching contactor made by ITE Imperial Corporation (Model A143F), were observed to be significantly charred or burned, with evidence of high heat (but no fire or smoke). The same relay and associated cable and connections were inspected on the other three diesel generators and found to be visually acceptable.

A replacement relay and cable from a Unit 2 diesel generator was installed in the D14 generator circuitry on May 6 and the engine was returned to service on May 8. The inspector discussed the failure with operations personnel and representatives from the field engineering group and observed the failed relay which had been removed from the D14 engine exciter circuits. The cause of the failure was attributed to improperly connected leads. The loose mechanical lugs were subsequently examined by corporate electrical engineering for failure and investigation. The K1 contactor damage was concluded to be caused by loose terminal connections. Electrical engineering's recommendations included the short-term immediate action of inspecting all K1 contactor terminal connections on the other three diesel generator engines including tightness checks of the auxiliary contact screw terminal lugs and the internal main contact bolts. A long-term recommendation was also made for a tightness check on a regularly scheduled basis during maintenance to cover the terminal lugs and internal contact bolts. The licensee is considering replace ment of the existing compression terminal lug which was supplied by the diesel manufacturer's cabinet subcontractor, Basler Electric, with the licensee's standard field termination using a lugged crimped terminal connection. The inspector reviewed engineering procedure E-1412 for wire and cable notes and details. Section 4.5 specifies the use of concentric Burndy dyes to crimp lugs. All connectors for terminating power cable were specified to be solderless long barrel, solid black Burndy lugs. The inspector also reviewed schematics of the power chassis for the nuclear exciter regulator on the diesel engines supplied by Basler Electric Co. Drawing 9-119801-910, Rev. C, depicts the 200 amp lighting contactor with latching 3-pole contacts used for the K1 relay. Subsequent discussions with field engineers and electrical engineering representatives indicate that the exciter circuits on the diesels responded properly and confirmed the failure cause to be loose mechanical connections. The licensee initiated maintenance requests to replace the mechanical connectors on the other three diesel engines exciter circuits and expects to complete this during the refueling outage. The inspector will follow those replacements.

The D14 diesel failure was analyzed by the licensee under Procedure ST-1-092-990, Unit 1 Diesel Generator Failure Report, and concluded to be the first valid test failure of a diesel engine since initial Unit 1 licensing. A special report pursuant to technical specification 4.8.1.1.3 is due for submittal to the NRC on June 4, 1987 to describe the diesel test failure. The inspector will review the licensee's analysis of the cause of D14 diesel generator failure when the special report to the NRC is submitted.

4.2 Reactor Enclosure Isolations

Licensee test engineers investigating a fire deluge system problem on May 8 left a compartment exhaust ventilation filter entry hatch open, causing a short circuiting of normal ventilation and a loss of normal differential pressure (negative) in the reactor enclosure. This resulted in a secondary containment isolation. The "A" reactor enclosure recirculation (RERS) and standby gas treatment system (SGTS) fans started, as designed, but the "A" RERS fan subsequently tripped on a low flow signal. The "B" RERS train was out of service at the time for damper maintenance, and a 12-hour TS action statement was entered until the maintenance was completed and the "B" train returned to service 2 hours later. The "A" RERS fan failure was found to be caused by a faulty pressure controller which was replaced, and the "A" train was returned to service on May 11. The reactor was at 78% power at the time and the event was reported to the NRC via the ENS phone.

An isolation of the secondary containment reactor enclosure had previously occurred on April 18 due to a low differential pressure signal created by an improperly isolated air supply to a fan controller. The SGTS and RERS properly initiated, as designed. Normal ventilation was restored following test engineer investigations. Another isolation of the reactor enclosure also occurred on May 15. All systems initiated, as designed, due to a false low differential pressure signal. The cause of the signal was personnel error in removing an instrument cap on a pressure sensing line associated with preliminary outage modification work.

The inspector discussed these events with licensee operations personnel and test supervision. While all activities were properly sanctioned and the events were appropriately reported to the NRC, the inspector expressed a concern for the increased frequency of reportable events attributable to personnel errors. Corrective actions associated with these events will be followed in future inspections and followup of the associated LERs.

4.3 RERS Fan Motor Breaker Failure

During a monthly surveillance test on April 16 of the SGTS/RERS fans and filters, that was being witnessed by the senior resident inspector, the "A" RERS fan failed to automatically start. A toggle switch on the 480 volt load center breaker cubicle feeding the fan motor was subsequently found to be in a "down" position. This condition prevented the breaker closing spring from being charged, and prevented the normally open breaker from closing on a start signal.

The inspector identified 20 separate breaker cubicles associated with the four safety-related 480 volt load centers located in the Reactor Enclosure which employ this type of toggle switch. The type K-600 circuit breakers made by Brown Boveri (formerly ITE Imperial Corp) are a stored energy breaker design capable of remote/auto opening and closing using motor-spring arrangements. The failure mode was previously described in NRC IE Information Notices 83-50 and 84-46.

All other potentially affected breaker cubicles were immediately inspected by the licensee and found to be operable. The RERS fans (A & B) are the only 2 of 20 safety related loads affected that would be not annunciated with the toggle switch defeated. Further followup of this event is described in Detail 5.2.4 for LER No. 87-011.

4.4 Incorrect RHR Hanger Installation

Post-modification review of a change under modification 86-5133 to the emergency service water (ESW) piping providing cooling water to the 'C' RHR pump room coolers and motor oil cooler revealed that an apparent incorrect hanger had been installed. The 'C' RHR subsystem was declared inoperable on April 15. Since the high pressure coolant injection (HPCI) system had bee blocked for preventive maintenance on a number of Limitorque valves, the plant entered a one-hour action statement after which a shutdown would have been required. HPCI was returned to service within 57 minutes, eliminating the need for a shutdown. The reactor was a 86% power at the time. The ESW pipe hanger was later determined by engineering representatives to be acceptable as-is, and 'C' RHR was made operable approximately 16 hours later.

The purpose of modification 86-5133 was to lower the flow resistance in the lines to the RHR room and pump motor coolers so that, as the piping ages, sufficient ESW flow through the coolers could still be maintained. The modification involved increasing the size of the ESW piping to the RHR pump compartment cooler inlets and also increasing the piping size to the RHR pump seal and motor oil cooler inlet and outlet piping. A revision to the modification resolved a concern previously identified by the licensee's PORC regarding routing the new piping on existing hangers. Additional drawings were added to the modification package detailing that portion of piping which could be done pre-outage, and also identified that portion of piping which was not permitted to be tied-in until the refueling outage.

The progress of modifications associated with ESW piping to the ECCS systems on Unit 1 scheduled to be completed during the refueling outage will be followed in future inspections. No violations were identified and the inspector had no further concerns.

4.5 HPCI Stop Valve Failure

The HPCI pump was manually shut down and declared inoperable on May 14 after the turbine stop valve failed closed and system flow and pressure were lost. HPCI had been running for 25 minutes during a quarterly functional surveillance test (last performed on February 14) when the stop valve drifted closed. Hydraulic oil was found puddled under the valve, and the actuator stem was separated from the valve body. The RCIC system had been successfully operated immediately prior to the HPCI failure, and all low pressure ECCS were verified by the licensee as available. Reactor power was 76% at the time of the HPCI failure, and the system remained inoperable for the next 24 hours until a cold shutdown condition was achieved to begin the scheduled refueling outage.

The valve is a hydraulically actuated plug valve manufactured by Schutte and Koerting and is skid-mounted on the HPCI Terry turbine.

The valve had been previously modified in 1985 during startup testing in accordance with General Electric service information letter number 352 issued on February 18, 1981. SIL 352 describes a required adjustment of the steam balance chamber pressure in the HPCI stop valve. The balancing chamber adjustment is required to prevent erratic opening of the HPCI stop valve identified with cold quick starting transients of HPCI and which has been experienced at other BWR plants. Damage to the stop valve seat, stop valve stem, and hydraulic cylinder seals was observed at other sites because of improper adjustment of the stop valve balance chamber pressure and a resulting stop valve opening transient. The adjustment assures stable opening of the turbine stop valve against steam forces in the balance chamber and is suggested to read between 100-180 psig under normal reactor pressure. Reactor steam forces under the stop valve's main disk as the valve leaves a full-closed position could catapult the valve full-open and closed almost instantaneously with potential damage to the stop valve assembly. The licensee had previously made the steam balance chamber pressure adjustment in accordance with SIL No. 352 during the power ascension test program.

Preliminary conclusions by the licensee's maintenance engineering staff supported a fatigue failure of the coupling into which the valve stem is threaded. The apparent cause of the fatigue was "jack-rabbit" starting of the HPCI turbine, most probably due to the steam balance chamber becoming out of adjustment. The licensee plans to disassemble the stop valve and inspect it during the refueling outage. The inspector reviewed maintenance division procedure PMQ-056-034 entitled "HPCI Turbine Stop Valve Overhaul" and discussed the proposed corrective actions for the valve failure with maintenance personnel. The inspector will review the results of the repair of the stop valve in future inspections.

5.0 Licensee Reports

5.1 In-Office Review of Licensee Event Reports

The inspector reviewed Unit 1 LERs submitted to the NRC Region I office to verify that details of the event were clearly reported, including the accuracy of description of the cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were involved, and whether the event warranted on-site followup. The following LERs were reviewed:

LER Number	Report Date	Cause(s)	Subject
87-006	3/20/87	Design Deficiency/ external	CREFAS actuations due to chlorine detector probe moisture intrusion from rain/snow
87-007	3/25/87	Procedure deficiency (error of omission)	IRM channel surveillance tests did not check inoperative function circuitry.
87-008	3/31/87	Component failure	CREFAS actuation due to indeterminate chlorine detector probe failure
87-009	4/6/87	Design deficiency/ external	CREFAS actuation due to chlorine detector moisture intrusion from overhead conduit condensation

LER Number	Report Date	Cause(s)	Subject
87-010	4/27/87	Procedure Deficiency (cognitive error)	Inadequate vent flow path for containment LLRT of drywell radiation monitor return isolation valves
87-011	5/14/87	Unknown	RERS fan automatic start prevented by inoperable breaker (closing springs discharged)

LER Nos. 87-006 through 11 are addressed in Detail 5.2 of this report.

5.2 Onsite Followup of Licensee Event Reports

For those LERs selected for onsite followup as noted in Section 5.1, the inspector verified that the reporting requirements of 10 CFR 50.73 and Technical Specifications had been met, that appropriate corrective action had been taken, that the event was appropriately reviewed by the licensee, and that continued operation of the facility was conducted in accordance with Technical Specification limits.

5.2.1 LER 87-007; Deficient IRM Surveillance Tests

On February 23, 1987, during the review of surveillance test procedures for the Intermediate Range Monitor (IRM) channel functional test, it was discovered that procedures did not include a check of the IRM inoperative function. An IRM inoperative functional check ensures that the IRM mode switch is in the correct position; if not, a half-scram and a rod block signal would be initiated. Verification of the IRM inoperative function is a requirement of Technical Specifications for the reactor protection and control rod block systems.

The inspector reviewed the licensee's evaluation of possible adverse consequences from this event. All IRM channel inoperative function circuitry was subsequently tested, with no failures, indicating that the circuits have been functioning properly since their installation. The licensee has also monitored the IRM channels during reactor startups and all IRMs have demonstrated a proper response to reactor core neutron flux. The licensee has modified the eight affected test procedures (ST-2-074-608-1 through ST-2-074-615-1) to check the IRM inoperative function. The inspector had no further questions, and identified no violations.

5.2.2 LER Nos. 87-006, 008, and 009; Deficient Chlorine Detector Probe Design

The inspector reviewed three LERs associated with chlorine probe failures leading to an isolation of the main control room and initiation of the control room emergency fresh air supply system (CREFAS). The failures of chlorine electrolyte probes have continued since the replacement of the C&D channel probes approximately one year ago with a different type of probe. The previous probe employed a cassette tape which frequently broke causing inadvertent isolations of control room ventilation. The new type of probe is manufactured by ANACON and is a model M17 electrolytic detector. The three reportable events during this inspection period were attributed to a false high chlorine concentration signal due to the presence of moisture on the analyzer probe. The moisture causes a chemical imbalance in the probe's electrolyte assimilating the high chlorine concentration. In one case reported in LER 87-009, condensed moisture from rain accumulating in overhead conduit associated with the D probe caused the isolation and CREFAS initiation.

The inspector reviewed the event with licensee I&C engineers and station management and observed the physical installation of the D probe in the control structure's ventilation intake plenum. The inspector observed the licensee's corrective action to install a silicon seal at the tops and bottoms of the electrical conduit to the C and D protectors under temporary circuit alteration TCA-907 on April 16, 1987. The inspector observed proper tagging of the TCA, PORC approval, and shift supervision approval prior to implementing the temporary fix to prevent water accumulation from reaching the probe.

LERs 87-006 and 008 reported similar problems with chlorine detector probes caused by different conditions. LER 006 described an event attributed to a design deficiency in that the location of the probe is one foot away from louvers allowing outside rain, snow, and wind to contact the probe. The moisture causes the chemical imbalance described above and isolates main control room ventilation. Corrective actions associated with this event described proposed modifications to relocate the analyzer probes away from external conditions at the louvers as well as a longer term modification to revise the control room ventilation isolation logic requiring two of the four chlorine analyzers rather than either one of the two (C and D) which is the current logic. This logic change had been delayed because the new detection system utilizing electrolytic probes was expected to be more reliable than the previous photo-optic analyzer tape.

In LER 87-008 a C channel chlorine isolation occurred due to an unknown cause. Based on previous experience the cause was attributed to either debris or water although neither was evidenced on the probe when it was replaced.

Based on the continuing design problems associated with chlorine detection systems at Limerick, the Senior Resident Inspector discussed the licensee's plans to modify the detectors to prevent events such as described in the LERs above. The inspector reviewed a letter dated April 14, 1987 from the licensee's project engineering group to Bechtel Power describing the current inadequacy of the main isolation logic because of the effect of a single detector failure on control room isolation. Modification number 0502 was re-proposed by engineering to charge the current one out of two logic to a one out of two taken twice logic utilizing existing channel A and B detectors. The inspector raised a concern about continuing design problems associated with the chlorine detection systems and that concern was shared by station management. A proposed temporary modification was also being considered as of the end of the inspection period which will be similar to long term modification number 0502 being pursued by design engineering.

The inspector had no further concerns and identified no violations.

5.2.3 LER No. 87-010; Invalid LLRT Procedure for Drywell Radiation Monitors

The inspector followed up on corrective actions proposed in LER 87-010 as a result of a local leak rate test discrepancy discovered on March 26, 1987. The test discrepancy was associated with local leak rate testing for the drywell radiation monitor supply and return penetrations 117B performed on an 18-month cycle. The test procedure ST-1-LLR-561 had been previously done on May 1, 1986 based on a recent revision to a test procedure on April 16, 1986. However, the revised test procedure failed to recognize internal check valves on the rad monitor skid which because of the changes in the procedure would block the intended vent flow path necessary to perform a satisfactory leak test because the adequate vent path did not exist any more due to the revisions of the test procedure. An improper accounting of leakage through valves SV-26-190C and 190D was obtained.

The licensee had identified this test procedure discrepancy during a review of all LLRT test procedures in preparation for the refueling outage. The procedure review was being performed to incorporate recently revised human factors improvements in the procedures. Upon the discovery of the discrepancy a successfull LLRT was performed on containment penetration 117B on March 26. Prior to that test, but after the discovery of the test procedure discrepancy, plant operators had blocked closed the isolation valves in question. The inspector reviewed the test data obtained from the retest of penetration of 117B and verified that all Appendix J limits were in accordance with technical specifications. The inspector reviewed a temporary procedure change to the affected LLRT test and verified that a proper vent path had been provided. The penetration leakage found was 184.08 sccm. The new value of penetration leakage increased the as-found type C total leakage to a total of 85,906 sccm. The technical specification limit or 60% La value is 96,500. The licensee reviewed test procedures for approximately 153 LLRT procedures to verify proper vent paths during the tests. No other discrepancies were identified.

Because the penetration did not fail local leak rate testing upon discovery of the procedural discrepancy and because this instance was isolated with no previous recurrent and similar instances, no violation was assessed. The licensee appropriately reported the details of this event in LER 87-010 and corrective actions were thorough and immediate. The inspector identified no further concerns.

5.2.4 LER No. 87-011; RERS Inoperability from Discharged Fan Breaker Closing Spring

As discussed in detail 4.3 of this inspection report the A reactor enclosure recirculation system (RERS) fan failed to start during a normal surveillance test because a toggle switch on a load center breaker cubicle feeding the fan and motor was in a down position. The toggle switch in the down position prevented proper breaker operation and caused the ARAS train to be inoperable.

The inspector discussed this event with licensee's operation personnel and field engineers. Similar events had previously been described in NRC IE Information Notices 83-50 and 84-46. Unit 1 was not operating at the time the information notices were issued. The inspector reviewed internal memoranda from the licensee's electrical engineering organization addressing the above NRC information notices. At that time the method for assuring the operational readiness of the breaker spring closing mechanisms was described to be a periodic test program on the breakers as well as periodic confirmation of the closing spring status flag. However, that review also indicated that all automatic lockouts and conditions disabling breaker cubicles would be indicated on control room annunciators. However, of the 20 safety-related load centers identified by the inspector as potentially affected by mispositioned toggle switches, only 2 would go potentially unannunciated (the RERS fan motor breaker feeders).

The inspector reviewed the occurence with licensee personnel who committed to immediate verification that all potentially affected load center breaker cubicles would be inspected for proper toggle switch position. No discrepancies were identified. The licensee added an explicit step for plant operators on plant rounds to daily log in the position of toggle switches and verify proper orientations. Additionally, operating procedures S93.9.A and B concerning 480 volt load center inspections were modified and approved on April 29, 1987 to include a check that the charging motor disconnect switch on all breakers is in the on (up) position. The inspector verified that step as included in the operating procedures 8.5. The inspector also verified that surveillance test ST-6-093-450 which is a weekly check of safeguards power distribution alignments and voltages was revised in step 6.5 to provide sign-offs of verification of the motor disconnect switch positions.

Finally, the inspector concluded that the cause of the toggle switch on the ARAS fan being in a down position was unknown but most probably due to an inadvertent disturbance by passing personnel. Because the breaker cubicle is located at the floor level on elevation 283 at load center D114, and because the toggle switch is unprotected, the possibility existed that personnel passing by could have inadvertently knocked the toggle switch down. The monthly test for exercising the ARAS fan had been successfully performed previously and the licensee had identified no subsequent maintenance or activities which could have mispositioned the toggle switch. The inspector concluded that all concerns had been addressed and no violations were identified.

5.3 Review of Periodic and Special Reports

Periodic or special reports submitted by the licensee were reviewed by the inspector. The reports were reviewed to determine that the report included the required information, that test results and/or supporting information were consistent with design predictions and performance specifications, and whether any information in the report should be classified as an abnormal occurrence.

The following reports were reviewed:

-- Monthly operating report for March 1987

-- Monthly operating report for April 1987

-- Annual Radiological Environmental Operating Report No. 3, dated April 24, 1987

These reports were found acceptable.

6.0 Surveillance Activities

6.1 Test Observations

The inspector observed the performance of and/or reviewed the results of the following tests:

-- ST-6-092-311 thru 314; Monthly Diesel Generator Operability Test Runs

-- ST-6-107-590-1; Daily Technical Specification Surveillance Log

-- ST-6-001-760-1; Main Turbine Stop and CIV Valve Exercise Test

-- ST-6-076-250-1; SGTS and RERS Flow Test

-- ST-6-095-901 thru 904; Weekly Safeguards Battery Checks

-- ST-6-093-450; 480 VAC Safeguards Power Distribution and Alignment Checks

-- ST-6-094-450; 120 VAC Safeguards Power Distribution and Alignment Checks

-- ST-6-049-230-1; Quarterly RCIC Pump and Valve IST

-- ST-6-107-885; Daily Thermal Limits Determination

-- ST-1-LLR-641-1; Leak Rate Test for "B" RHR Pump Test Return Line

-- ST-6-107-760; Weekly CRD Exercise Notch Testing

The tests were observed to determine that surveillance procedures conformed to Technical Specification requirements; proper administrative controls and tagouts were obtained prior to testing; testing was performed by qualified personnel in accordance with approved procedures and calibrated instrumentation; test data and results were accurate and in accordance with Technical Specifications; and equipment was properly returned to service following testing.

No unacceptable conditions were noted.

6.2 Rosemount Trip Unit Heat Sensitivity

On April 17, 1987, an inadvertent automatic depressurization system (ADS) permissive signal was annunciated in the main control room. The same spurious signal had also occurred on March 11, 1987. The licensee's original investigation revealed that two trip units (PIS-51-1N655C/1N656C) experienced increased trickle-current when subject to increasing temperature conditions. Rosemount Inc., the manufacturer of the trip units, confirmed that other sites have reported trip units (Model 510) with leaky output transistors but no data exists on the effects of temperature versus leakage current output. The vendor recommended replacement of the trip units; and the licensee subsequently replaced the faulty units. The inspector discussed the problem with licensee I&C engineers and observed proper Rosemount responses on a number of later occasions during tours of the Auxiliary Equipment Room.

No violations were identified.

6.3 Turbine Control Valve Pressure Switch Vibration

On May 2, 1987, pressure switch PS-01-102D used for the main turbine control valve No. 3 fast closure trip for 'B' RPS and end-of-cycle recirculation pump trip (EOC-RPT) would not reset after a control valve stroke test. The licensee's investigation revealed a loose termination at the switch. A similar event occurred on April 25, 1987 involving a similar pressure switch for turbine control valve number No. 1 which had been the cause of a number of spurious half-scrams.

I&C and test engineer troubleshooting involved manipulation of EHC pressure, inspection of the switch's electrical conduit, and re-stroking the No. 3 control valve. The switch was reset and no spurious half-scrams occurred for the remainder of the inspection period. Modification number 800 is scheduled to be implemented during the refueling outage and will move the four pressure switches (PS-01-102A,B,C,D) to a new location to reduce vibration related switch problems. The switches are ITT Barton Model 580-A-1 type that are being considered for long-term replacement with a different type. The inspector had no further concerns.

6.4 ECCS-RHR Low Pressure Permissive Interlock

The licensee performed the calibration of the low differential pressure permissive for RHR injection set at 78 psig (decreasing). Test procedures ST-2-051-420 thru 423 were performed on March 6 and 7, 1987 to calibrate transmitters and trip units for channels A-D. The inspector reviewed the completed calibration data sheets for all four channels and discussed test results with I&C personnel. No adjustments were required to either the transmitters or trip units since as-found readings were found to be within acceptable limits.

The importance of the low pressure permissive calibrations for RHR-LPCI injection is emphasized in the Limerick Unit 1 PRA. The dominant failure mode for low pressure injection leading to core damage involves postulated miscalibration of the above pressure channels which causes failure of the differential pressure permissive; thereby preventing LPCI flow into the reactor vessel. The PRA also assumes that the miscalibration is combined with a failure of control room operators to recognize that the injection valves HV-51-017A thru D have not automatically opened.

In a November 5, 1986 letter to the NRC, the licensee proposed a change to the trip setpoints of the LPCI differential pressure permissives in order to increase the range of the instrument loops. The low pressure interlock is intended to protect RHR piping upstream of the injection valves. The currently installed transmitters and trip units monitor a range of 0-800 psid, but are set at 78 psid, to accommodate the normal RHR discharge piping (125 psig via the condensate transfer system for keep-fill protection) pressure. When plant shutdown reduces reactor pressure to below normal RHR discharge pressure, the measured differential pressure across the injection valves becomes negative and is no longer within the calibrated range of the instrument loop. The shutdown condition eventually causes a trip unit gross failure condition and false annunciation of RHR out-of-service in the main control room. The proposed correction is for an increased range transmitter, new values of instrument loop and calibration accuracy, and a revised setpoint of 74 psid (4 psi lower than the existing value) requiring a change to the Technical Specifications. The proposed license amendment had not been approved as of the end of the inspection period, and pending issuance of the changes and recalibration of the LPCI permissives, is unresolved (50-352/87-09-03).

6.5 Surveillance Test Failure Trends

The licensee initiated a new routine test RT-1-107-990 to schedule a summary of all technical specification test failures. Failure trends are analyzed and reported to the PORC every six months. The initial failure report was assembled using computerized test records from the STARS system and covered the period of January through December 1986. The summary was reported at PORC Meeting 87-027 on March 26, 1987. The PORC concluded that no adverse trends were discernible to date. The inspector reviewed the summary results and discussed their significance with test engineering supervision.

No violations were identified and no concerns were raised.

7.0 Maintenance

The inspector observed selected maintenance activities on safety related equipment to ascertain that: the work was conducted in accordance with approved procedures; proper equipment permits and tagging were administratively controlled; craft performing the work were appropriately qualified and supported; and return-to-service of equipment included adequate post-maintenance testing and operational verification.

7.1 Work Observation

Portions of the following work activities were observed or reviewed:

-- MRF 86-070, RCIC pump bearing oil change

-- MRF 86-079, RCIC barometric condenser pump motor meggar

No violations were identified.

7.2 HPCI Overspeed Trip Mechanism

Inoperable overspeed trip mechanisms on the HPCI Terry turbine had been previously experienced at other BWR sites and was the subject of GE Service Information Letter (SIL) No. 392 issued on February 10, 1987. SIL 392 was a followup to a previously issued Rapid Information Communication letter (or RICSIL) No. 004 dated May 23, 1986.

The cause of the overspeed mechanism binding is a lubricant attack on the polyetherurethane part in the mechanism. The polyetherurethane tappet head assembly of the trip mechanism is located in a housing where it is exposed to lubricating oil and oil vapor. After exposure to aromatic hydrocarbons, the tappet head assembly may swell and restrict the tappet freedom of movement. The oil-induced swelling was recommended to be corrected by either replacement of the tappet assembly in the mechanical overspeed trip device or by modification to the existing tappet diameter to reduce the cold diametrical clearance between the tappet and valve body to 12 mils +/- 1 mil.

The reduced diameter was obtained by machining the tappet head stem to a 0.738 - 0.740 inch size under maintenance request form (MRF) 86-5236 in July 1986. The licensee also prepared a monthly operability check of the overspeed trip assembly to assure that no binding was occurring for the Unit 1 HPCI turbine tappet. Test procedure RT-1-055-330 was approved on August 4, 1986 and has been successfully performed monthly since that time.

The inspector observed the performance the overspeed trip operability check on March 30, 1987. The HPCI DC oil pump was started in order to open the turbine stop and control valves; the overspeed trip was manually pulled upwards causing the stop valve to close (as observed by stem movement); the overspeed trip condition was removed by releasing the assembly; and, the time from release of the trip until stop valve opening begins was verified to be within 3 to 6 seconds per the HPCI vendor manual. The test assured proper overspeed trip operation (no tappet binding) and resulted in a trip reset time of 4.72 seconds. The inspector had no further questions, and identified no violations.

7.3 Hydrogen Recombiner Isolation Valve

On April 24, 1987, while performing a preventive maintenance procedure on the 'B' post-LOCA hydrogen recombiner isolation valve HV-57-164, the maintenance craftsman noticed that the motor operated valve (MOV) position indication arrow indicated past the full-closed mark on the operator housing. The condition was reported to shift supervision, and an investigation was initiated including the following troubleshooting:

- Utilizing the MOV handwheel, the valve was manually stroked and observed to stroke full open (indicating greater than 90 degrees of travel). Visual observation of the valve shaft revealed that it appeared to only stroke 90 degrees.

- The MOV position indication cover plate was removed allowing observation of the end of the valve shaft relative to motor operator position. The MOV was manually stroked closed and the valve shaft observed as stopped when the MOV reached the full closed mark. However, the MOV Limitorque operator continued to travel to the mechanical stop in the operator.

The licensee concluded that the key which links the valve shaft to the operator shaft appeared to be degraded to the point where slippage occurs between the two shafts as the valve disc travels into its seat. To assure that the valve disc was seated, the full-closed mechanical stop was backed-off two turns and an operator attempted to handcrank the MOV further closed. The valve shaft did not move any further, indicating that the valve disc was driven firmly into its seat. After the valve was cycled several times, it was confirmed to be fully shut. The valve was mechanically fixed by positioning the opening and closing mechanical stops to prevent valve travel. The valve handwheel was chained and locked closed, and the MOV feedswitch was de-energized. A mechanical stop was also fabricated and placed around the valve shaft to prevent rotation of the valve disc. Finally, the 'B' recombiner was declared inoperable.

The PORC was convened on April 27, 1987 (Meeting 87-036) to review the valve problem. The PORC concluded that containment isolation valve HV-57-164 was closed, and that penetration X-201A was effectively isolated. Repairs to the valve are scheduled to be performed during the refueling outage. The valve is a single isolation valve on penetration X-201A and was part of a temporary exemption to Appendix J and License Condition No. 11 to install an additional automatic isolation valve by the first refueling outage. The valve manufactured by Clow Corporation was also one of 15 identified in a Part 21 report issued on March 13, 1986 concerning a potential for galvanic corrosion failure between the valve bearings and shaft. The licensee had been performing a weekly stroke test of valve HV-57-164 under special procedure ST-6-B57-200 to assure operability until the bearings could be replaced.

The inspector concluded that the disc overtravel of HV-57-164 is apparently unrelated to the potential bearing corrosion concerns. The valve had been successfully stroked closed weekly from March 1986 until the failure was observed on April 24, 1987. Further, the bearings of all affected Clow valves (including HV-164) are being replaced during the outage under modification number 980, and an additional HV-57-169 isolation valve is being added in penetration X-201A to satisfy License Condition 11. Repairs to HV-57-164, and the above modifications, will be followed in future inspections.

7.4 Diesel Fuel Oil Tubing Leak

On March 25 following a monthly surveillance test run of the D13 emergency diesel generator engine, an operator on his rounds discovered fuel oil on the floor in the vicinity of the engine at the number 11 and 12 cylinders. On the following day a small pinhole leak was discovered on the cross around piping assembly in the fuel oil system for the engine. The pinhole leak was on the east side of the engine near the fuel filter outlet. The licensee removed the fuel line under maintenance request form 87-2239 and sent the copper tube cross around piece to the corporate metalurgical lab for lab analysis.

The fuel oil supply piping is small copper tube under approximately 20 psi. A similar failure had been experienced on the D14 engine on February 3, 1986. The licensee requested the metalurgical analysis of the failed fuel line on D13. The fuel oil cross around pipe assembly was approximately 18 inches in length and is Colt Industry's part number 16-604-784. The fuel line was purchased as a commercial grade item with no ASME Class III requirements. A very small fuel oil stream approximately the diameter of a 5 mm pencil lead was observed. The licensee's maintenance engineering representatives contacted Colt Industry to resolve a number of questions raised as a result of the failure. The licensee ascertained that Colt uses copper fuel oil lines routinely on diesel engines and that no similar failures have been reported from other Fairbanks Morse engine owners. There are approximately 50 Colt engines similar to the engines at Limerick. Manufacturer's records showed only 2 replacement fuel lines have been shipped to sites other than Limerick.

The previous failure in February 1986 of a fuel cross around piece on the D14 generator was documented and repaired under maintenance request 86-856. The fuel line tubing was replaced using spare Unit 2 tubing but no metalurgical analysis was requested at that time. The inspector ascertained that the replacement of the D14 diesel tubing in February 1986 had been properly procured in accordance with administrative procedure A27.9 and that a proper equipment substitution record receiver had been pursued. No special service life or environmentally qualified life was identified for the tubing.

The results of the metalurgical analysis 87-178 report indicated that the defect was extremely tight and hard to find. Utilizing dye penetrant, examinations, the licensee's metalurgical engineers were only able to find the defect after splitting open the tube diagonally. No contaminants or corrosion products were found in the vicinity of the point of failure. A readily identifiable cause could not be conclusively identified. The licensee's engineers concluded that the failure found adjacent to the inside bend radius of the tube was most probably caused by inside diameter initiated erosion most probably at a localized point due to high velocity flow or cavitation damage. The metalurgical report recommended that two more cross around pieces presumably from the D11 and 12 diesel engines on Unit 1 be provided. The inspector will follow the progress and investigation of diesel fuel tubing corrosion during the scheduled overhaul of all four engines during the refueling outage.

No violations were identified.

7.5 Scram Pilot Solenoid Valve Leakage

On February 26, 1987, a half scram occurred on RPS channel A1 due to a blown fuse which fed a turbine control valve fast closure switch. During the half scram, a scram air header low pressure alarm was received. Normal 70-75 psig air pressure was recovered following reset of the half scram signal, and the alarm was reset. The scram pilot solenoids were checked for air leaks at the retaining nuts, and seventy-four HCUs were identified with leaks. One scram solenoid had a retaining nut missing.

Maintenance requests were initiated to repair the air leaks on 74 scram pilot solenoid valves (SV-1-17) at the housing "acorn" nuts. There are two dual-ASCO solenoid valves (SV-1-17 and 18) installed in series on each of the 185 control rod HCUs. The SV-1-17 solenoid de-energizes and repositions upon receipt of an 'A' side RPS scram signal; the SV-1-18 valve repositions to vent scram air pressure to atmosphere upon receipt of an RPS 'B' signal. The source of the leakage path was found to be from a loose nut on top of the solenoid coil located on the 'inboard' SV-1-17 valve. However, the leakage stopped whenever the 'outboard' SV-1-18 valve repositioned (i.e., RPS 'B' scram) due to how scram air is piped in parallel to each set of HCU scram pilot valves. Scram air leaks were previously documented in GE Service Information Letter (SIL) No. 90 issued on July 31, 1974, stating that over an extended period of time the nut on top of the solenoid coil located on the scram pilot valves may become loose. The loose nut permits air to leak from the scram pilot valve which in turn can cause sluggish scram valve reset action. GE recommended inspection of the scram pilot valves and repair of air leaks found. Loose solenoid valve nuts should be tightened; however, 100 in-lbs torque should not be exceeded. Upon persistent leakage, the condition of the O-ring under the nut is recommended to be examined and replaced if damaged.

The licensee adjusted pressure regulating valves in the scram air supply lines to maintain normal air header pressure. However, upon receipt of a 'B' RPS scram (whereupon the SV-1-17 valve leakage stops), a higher than normal scram air header pressure is then experienced. However, engineering evaluation of the higher scram air header pressure concluded this to be an acceptable condition that does not significantly change CRD scram times, since the venting cross sectional area for individual rod scrams, alternate rod injection (ARI) and backup scrams is so large. Operating at a reduced scram air header pressure was concluded to be more conservative than operating at normal pressure.

A strip chart recorder was set up under TCA-874 to monitor and record scram air header pressure continuously to ensure the pressure oscillations resulting from the scram pilot valve leakage did not worsen. A temporary circuit change for the leaking valves will be scheduled to be torqued as per SIL #90 during the upcoming refueling outage.

The inspector observed proper 70-75 psig scram air header pressure routinely during the inspection period. Physical inspection of scram pilot air valves on all 185 HCUs verified no further additional leakage. Maintenance request 87-1518 was immediately initiated on February 27 to replace the solenoid housing nut on the pilot valve housing of HCU 50-27 which was the most significant leak found. The remainder of HCUs identified to be potentially leaking will have their pilot air valves repaired at the refueling outage. TCA-874 was removed on May 11 and the inspector had no further questions.

8.0 Plant Modifications

The following modifications were evaluated to assess, in part, the: details and adequacy of the safety evaluation; proper consideration of Technical Specification changes; implementation under Administrative Procedure A-14; the status of completion of physical installation; effectiveness of modification acceptance testing; and, accurate update of operating and test procedures, as-built drawings, and operator training programs. The inspector verified that appropriate engineering design support and PORC review and approval were received; that Construction Division installation was in accordance with ERDP procedures including appropriate QC coverage and with a minimal effect on plant operations; and, that an operable system was returned to service with no apparent unreviewed safety questions. Within the scope of this inspection, no violations were identified.

8.1 SGTS Tie-In To Refueling Floor Zone

Modification (MDCP)-614 is intended to provide larger fans and new ductwork for the Standby Gas Treatment System (SGTS) to tie-in the systems to the refueling floor ventilation zone. Limerick Full Power License Condition No. 14 requires that, prior to any movement of irradiated fuel within the refueling floor volume, the licensee shall complete and test all modifications required to connect the refueling floor volume to the SGTS.

Revision 5 to Modification 614 enabled temporary connection of the refueling air zone to the original SGTS fans during the beginning of the refueling outage to permit handling of irradiated fuel. The bases used to determine the acceptability of removing the primary containment head prior to the connection of the SGTS to the refueling area were documented in a letter requesting approval by the NRC. Revision 5 to MDCP-614 was issued to implement the temporary change during the first week of the refueling outage. The remainder of the modification work to permanently connect the refueling floor to SGTS is detailed in the previous revisions of MDCP-614.

Technical Specifications require Reactor Enclosure secondary containment integrity be maintained in Operational Conditions 1-3 (Power Operations through Hot Shutdown), and that refueling area secondary containment integrity be maintained when irradiated fuel is being handled and during core alterations and operations with a potential for draining the reactor vessel. In view of these requirements, the licensee requested NRC approval prior to removing the drywell head (without SGTS connected to the refuel floor). The licensee's PORC identified situations that require secondary containment integrity to be established in the Reactor Enclosure during refueling operations. The PORC met to discuss an example where, if both of the required ECCS subsystems become inoperable, core alterations are to be suspended and all operations with a potential for draining the reactor vessel must stop. This possibility occurs for a few days at the beginning and at the end of the outage, when the reactor cavity is not flooded. Administrative controls associated with the outage schedule will maintain three ECCS subsystems available at all times. Special procedure SP-033 was developed in response to the inspector's concerns to provide guidance to reestablish secondary containment integrity during the installation of MDCP-614. The special procedure addressed opening two SGTS slide gate dampers which isolate the reactor enclosure, maintaining certain ST's in surveillance, and amplified information already provided in GP-6.2.

The inspector reviewed the status of modification 614 completion, discussed the safety evaluations with licensee test engineers, and walked-down completed portions of the work. No additional concerns were identified and the inspectors concluded that the licensee was meeting the requirements of License Condition 14.

8.2 Automatic Chilled Water Isolation Valve

License Condition 10 requires the addition of automatic isolation signals to the reactor enclosure cooling water (RECW) and to the outboard drywell chilled water (DCW) containment isolation valves. Modification 84-106 is required to upgrade the design of the isolation valves to meet the requirements of General Design Criterion 56. New isolation signals will cause drywell chilled water valves HV87-120A,B, 121A,B, 124A,B, 125A,B, and reactor enclosure cooling water valves HV13-106, 107, 108, and 111 to be isolated on the receipt of either a drywell high pressure signal or low reactor vessel water level signal. Modification 84-106 was originally intended to be installed prior to the outage, but was delayed because of concerns regarding possible inadvertent isolation of the water supplies to the reactor recirculation pump seals while the pumps were running. The licensee's identified concern was that possible seal damage could ensue but yet be undetected.

Additional concerns were raised such that inclusion of the high drywell pressure isolation of these valves would prevent appropriate remedial actions associated with a small break LOCA. In particular there would be no provisions for bypassing the isolation of the RECW supply to the recirculation pumps. Because of this potential problem during a small break LOCA, cooling water to the pump seals would be isolated which could result in seal failure increasing the magnitude of the LOCA. MDCP 84-106 was therefore remanded by the licensee's PORC to engineering personnel for further evaluation. In order to meet License Condition 10, the licensee has decided to implement the orignally intended modification pending further evaluation of potential recirculation pump seal damage.

8.3 Scram Inlet Valve Seat Ring Replacements

Modification 85-670 is planned to be performed during the outage for approximately one-third of the CRD hydraulic control units (HCU's). The modification involves replacement of the inlet scram valve teflon seat rings with a tefzel seat ring material. Vendor information has identified that the teflon seat rings have been flaking off, and have obstructed flow through cooling water orifices in the control rod drive causing high temperatures in the control rod drive mechanism. The new tefzel seat ring material will eliminate the problem of teflon flakes.

The inspector reviewed the safety evaluation for MDCP-670, discussed the modification with cognizant reactor engineers, and reviewed operational history of CRDs. As of the end of the inspection period, 29 CRDs had exhibited temperatures above 250°F, with the following distribution:

Temperature Range	Number of CRDs
250 - 299	15
300 - 349	6
350 - 399	3
400 - 450	5

Reactor engineers indicated that the drives running hot and identified above would be included in the number selected for scram inlet valve seat replacements.

8.4 Clow Valve Bearing Replacement

Modification No. 980 is planned to replace the existing carbon sleeve bearings with bronze bearings in Containment Atmospheric Control System (CACS) butterfly valves manufactured by Clow Corporation. The replacement is being done based on a failure of two Clow butterfly valves (procured on Limerick specification 8031-P-144) installed in a similar system at Peach Bottom and reported to the NRC under 10 CFR Part 21 on March 13, 1986. The shaft of each valve had bonded to the upper and lower sleeve bearings such that disc movement was severely restricted. The root cause of the failure was found to be chloride contamination in the carbon (graphite) bearings.

The carbon steel bearings provide shaft support for 15 Clow valves installed in the Limerick Unit 1 CACS. The replacement bearings will be manufactured from ASTM B505 Alloy 932 bronze material. The bronze bearings are being supplied by C & S Valve Company (formerly Clow Corporation). B505 Alloy 932 bronze is listed on the Clow valve drawings as an alternate bearing material. C & S has confirmed that bronze is acceptable as an alternate bearing material for the subject valves and that use of the bronze bearings wil not adversely affect operation of the valves.

The licensee concluded that the bearing replacement is considered a normal maintenance activity, and not a modification, since bronze is listed as an alternate bearing material on the vendor's drawing. Consequently, maintenance will perform the bearing replacement using a safety evaluation to support the work under MRF Nos. 87-1539 through 1542. The inspector agreed with the licensee's conclusions, and identified no concerns or violations.

8.5 "Live" Packing Replacements

Modification 86-5054 implements a valve stem packing substitution program using Chesterton graphite packing, reduced packing depth, carbon sleeves and live-loaded glands. MDCP 86-5054 is a generic modification to reconfigure existing valve stuffing box arrangements for a total of 76 safety related valves. The modification provides a more efficient and reliable stem seal with less frictional drag. The Maintenance procedure which will direct the repacking of these valves also includes tightening of any leak-off plugs which will no longer be functional as a result of the modification. Maintenance plans to develop a method for ensuring the tracking of valves which have been repacked under this modification to ensure their proper treatment in future maintenance activities. Valve selection criteria included high pressure systems inside of the drywell which typically are larger motor-operated valves and others that have exhibited past packing leakage. Of the total 76 valves being worked during the refueling outage, 25 will receive live-loaded glands based upon engineering evaluations and dimensional analyses. All valve packing will be changed to Chesterton graphite and the numbers of packing rings will be reduced to five.

The inspector reviewed the safety evaluation for modification 86-5054, discussed it's buses with cognizant mechanical engineers, and reviewed the proposed work packages with maintenance representatives. Work in-progress will be observed during the upcoming outage.

9.0 Independent Inspection

The following details are based on followup of generic industry problems or plant events that have potential safety significant concern for the Limerick Unit 1 design. The topics selected are based on NRC Information Notices, vendor technical information letters, generic industry experiences and inspector judgement.

9.1 Scram Inlet Valve Diaphragms

On April 1, 1987, at the Nine Mile Point site, a scram inlet valve diaphragm failed. The valve (HCU 126) did not open on a loss of actuator air pressure, resulting from the ruptured diaphragm. No control rod movements were experienced; however, the control rod had to be manually inserted to replace the diaphragm. The failed diaphragm had a 7-1/4 inch diametric tear, and small radial cracks at the center (where the actuator attaches) were observed. The diaphragm had been in service since 1974.

The Limerick Unit 1 preventive maintenance program ensures that scram inlet and outlet valve diaphragms will be replaced in lots of one-third, beginning with the fourth refueling outage. The diaphragms are made of Buna-N material and have a 6-1/2 year qualified service life. Qualified service life begins after a diaphragm is installed, and is separate from the manufacturer's shelf life.

The inspector reviewed the licensee's plans to perform preventive maintenance on HCU's during the refueling outage, including scram pilot solenoid and accumulator maintenance. The scram inlet/outlet preventive maintenance schedule was discussed with maintenance personnel, and confirmed to be scheduled for the fourth refueling outage. No diaphragm failures have been experienced at Limerick to-date, and the HCU's have been in service for approximately three years. The inspector had no further questions, and will follow the HCU outage maintenance in future inspections.

9.2 Fairbanks/Morse Diesel Cylinder Liners

A diesel generator at Three Mile Island experienced scoring of a new cylinder liner while being tested in January 1987 following cylinder liner replacement. The diesel engines were similar to those installed on Limerick Unit 1 Fairbanks Morse Model 3800TD81/8. Analyses of the scored liners and the data taken during the TMI engine run-in determined that the scoring was caused by reduced piston clearances, caused by the following four conditions:

- an additional oil drain ring was installed on the upper and lower pistons per Fairbanks Morse Repair Service Information Letter RNS3855874. The ring reduces the amount of lubricant between the lower piston and liner, resulting in a higher piston temperature.

- fuel injection timing was reset (in the field) to achieve cylinder firing pressures in accordance with Fairbanks Morse engineering instruction number 4403FX. The adjustment of the injection timing from 38 to 42 degrees resulted in a higher piston and exhaust temperatures.

- The Fairbanks Morse run-in sequence (in accordance with Fairbanks Morse Service Information Letter Volume A, Issue 5) prescribed several running periods at reduced load. This operation involves a "transition area" in which the scavenging air blower provides adequate scavenging air and higher load levels at which the exhaust driven turbo-charger reaches a speed that provides adequate scavenging. Operating in this "transition area" also results in a higher piston and exhaust temperatures.

- The initial run-in procedure was completed with a differential jacket water temperature (across the engine) in excess of Fairbanks Morse recommendations.

Corrective actions taken for the TMI diesel engine involved: (a) removing the oil drain ring that had been added in the vacant groove in the lower piston; (b) adjusting the fuel injection timing to 40° for the run-in sequence; (c) adding additional run time at low loads and load increases through the transition period; (d) adding more inspections and monitoring; (e) replacing an orifice in the jacket cooling water system to maintain the jacket coolant temperature change across the engine in the recommended 5 to 8°F range.

The inspector discussed the potential for diesel cylinder liner damage at Limerick with responsible test, design and maintenance engineers. The Limerick engines are similar to the TMI diesels, and are an opposed piston 12-cylinder Model 38TD81/8 turbo charged design with 8.15 inch clinder liner diameters. The Fairbanks Morse Operating and Maintenance Manual specifies a maximum cylinder liner concentricity tolerance of 3 mils, beyond which an eccentric ring dimension would cause a combustion blow-by problem and high piston and exhaust temperatures. The licensee plans to overhaul all four Unit 1 diesel engines in accordance with the 18-month maintenance examination procedure M-020-002. Step 7.4 of M-020-002 specifies an examination of all cylinders and pistons; replacements, if necessary, will be performed under procedure M-020-010. The engines were last overhauled in May 1986 but no piston liners were either modified or replaced.

The inspector will follow the engine overhauls scheduled during the refueling outage to assure that liner repairs appropriately consider the TMI experience, and that injection timing and run-in procedures are in accordance with Fairbanks Morse recommendations. The inspector had no further concerns.

9.3 General Electric HFA Relays

General Electric issued a relay and accessory service advice letter dated November 14, 1986 reporting incorrect operation of HFA auxiliary relays. Service advice letter number 188.1 was issued to GPU Nuclear Corporation on January 9, 1987 instructing that licensee that they had been furnished HFA relays which may require adjustment or replacement. The relay failure mode concerned continuously energized AC power relays that failed to provide contact operation when de-energized. The root cause suspected was mechanical binding preventing correct relay operation caused by incorrect location of a stop tag welded to an armature. In conjunction with minor movement of the magnetic assembly the condition caused vibration when the relay was energized with AC power and caused the armature to bind. Relays manufactured in batches between January 1983 and October 1986 were suspect by General Electric, and the service advice letter recommended technical checks to determine if the relay binding was present.

The inspector discussed the service advice letter with licensee field engineering representatives. The inspector reviewed electrical schematic E-164, Sheet 2, Safeguards Bus Scheme, for the four 4KV buses. The inspector also reviewed a relay tabulation on the E-164 schematic which showed that none of the GE type HFA relays had normally closed contacts. Further, the relays affected were all normally de-energized utilizing DC relay power. A total of 12 HFA type relays were found in Unit 1 circuitry. Electrical schematic E-21-1040-E, 6.15, depicts core spray logic and shows the K18 relay used in LOCA/ECCS logic to initiate emergency diesel generator starts. The K18 relay is a normally de-energized DC relay whose three contacts are normally closed. Schematic E-164 shows two GE type HFA relays on each of the four safeguards buses. The relays are 144-X-115, a sequential loading permissive relay on each of the four safeguards buses, and an undervoltage relay 127X-115 for low bus voltage. The sequential loading permissive relay is normally energized. The low bus voltage relay is not. Both DC relays have normally opened contacts.

The inspector concluded that a total of 12 HFA type relays were utilized in safety related circuits on Unit 1 but that none were susceptible to the potential binding described in General Electric service advice letter number 188.1. The inspector's conclusion was based upon the fact that, with the exception of the sequential loading permissive relays in the safeguards buses, the relays are not continuously energized, do not receive AC control power (a contributor to the vibration and loosening of the armatures), and the contacts are normally open. The apparent mechanical binding of GE HFA armature assemblies is a concern for relay operation in continuously energized AC applications, a condition not installed at Limerick. The inspector had no further concerns, and no violations were identified.

9.4 Planned Manual Reactor Scrams

The inspector discussed the licensee's practice of manually scramming the reactor from less than 30% power during planned shutdowns. Licensee representatives from reactor engineering, test engineering, and General Electric service representatives were present to discuss the significance and effect on equipment associated with manual reactor scrams. The General Electric test representative had performed an informal survey of boiling water reactors to ascertain the use of this practice. Of the 14 BWRs sampled, seven were found to routinely manually scram the reactor during planned shutdowns, three of the 14 plants did not have a common practice, and four of the plants did manually scram as a convenience as opposed to inserting rods fully to a shutdown condition. The inspector concluded that manual scrams during planned shutdowns is a common practice in the industry.

The inspector reviewed Limerick General Procedure GP-3 entitled "Normal Plant Shutdown", Step 3.1.13 which directs the operator to scram the reactor manually upon the approval of the Reactor Engineer using a mode switch scram (i.e., mode switch to the shutdown position). The scram step follows a step requiring verification that the rod sequence control systems and the rod worth minimizer system are operating properly and are automatically placed in service. An alarm indicating that these systems are to be placed in service is received at from 30-35% power, the low power setpoint at Limerick at which the systems enforce proper rod sequencing is 27% power.

The inspector also reviewed General Electric document 21A8781 entitled, "Control Rod Drive Design and Performance Requirements for Limerick". The inspector discussed the design envelope for minimum performance of control rod drives and the effect of cycling HCUs during manual scrams on proper scram system performance. The primary concern is for wear of internal seals on the drive mechanisms and the effect upon scram times of the rods. Control rod drive seal wear experience has been such that increased wear can be correlated with increased probability of seal rupture. The General Electric HCU design is over 20 years old, and the worst case design basis is based on a drive which is almost fully inserted (notches 6-12) with the reactor depressurized at 30 psig. In this case a scram would accelerate a rod at that design basis notch position to 75 inches per second which would be rapidly stopped because of the buffer piston which begins to take effect at notch 4. Even under those design basis conditions, the HCUs in drives are qualified for 300 scram cycles plus an additional 300 startup scram cycles. This design basis for the HCUs and drives is documented in the General Electric design and performance requirement, and is based on tests of a prototype CRD. The CRD has a 40-year design life and 5-year maintenance life and in addition to the 300 full-stroke scrams and 300 startup scram cycles, an additional 100 maintenance scram cycles are included. The inspector concluded that given the relatively low number of unplanned scrams that Limerick experiences and the relatively high number of scram cycles for which CRDs are designed, the planned manual scrams contributed essentially no additional mechanical stress on the drive seals beyond design basis.

Another consideration affecting the licensee's decision to manually scram the reactor is surveillance test requirements containing technical specifications for CRD scram times and for scram discharge volume vents and drains. Scram times for rods must be conducted at greater than 950 psig, and scram discharge volume vent and drain surveillances must be conducted at greater than 50% rod density. Both of these considerations contribute to the licensee's decision to manully scram the reactor rather than shutting down by individual rod insertions below 25% power. There's also a time constraint associated with individual rod sequences below 25% power as RWM and RSCS enforce. The inspector concluded that manual scramming of the reactor in planned shutdown evolutions is a common industry practice and does not adversely contribute to drive seal wear or seal rupture probability. Further, the safety significance of a ruptured seal does not significantly affect notch or drive speed of a CRD and will result in a slightly slower scram time but not in a failure of a control rod to scram. The inspector had no further concerns and no violations were identified.

9.5 NRC Information Notice 86-96, Heat Exchanger Fouling

The inspector discussed the maintenance of the Unit 1 RHR heat exchangers with representatives from test engineering and maintenance. The licensee internally addressed NRC Information Notice 86-96 in a memorandum from the Station Manager to the Corporate Engineer-in-Charge of Licensing dated February 25, 1987.

Information Notice 86-96 addresses the degradation of safety related heat exchangers due to mud, silt buildup and corrosion. Because Limerick has exhibited susceptibility to this problem with heat exchangers using emergency service water and service water, a preventive maintenance program to inspect and clean heat exchangers was established. Also, NALCO Chemical Company has applied a chemical treatment program to the Limerick service water systems. To ensure adequate flow, routine tests are being established to flow balance ESW and service water systems during the first refueling outage. The established frequency for subsequent testing is under consideration by the licensee, and the outage flow balancing will be followed during future inspections.

10.0 Exit Meeting

The NRC resident inspectors discussed the issues in this report throughout the inspection period, and summarized the findings at an exit meeting held with the Station Manager, Mr. John Franz on May 15, 1987. At the meeting, the licensee's representatives indicated that the items discussed in this report did not involve proprietary information. No written inspection material was provided to licensee representatives during the inspection period.