U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 87-28

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: November 1 - December 10, 1987

Inspectors: E. M. Kelly, Senior Resident Inspector
L. L. Scholl, Resident Inspector
J. H. Williams, Project Engineer
A. G. Krasopoulos, Fire Protection Specialist

Reviewed by: J. H. Williams — 1/12/88
J. H. Williams, Project Engineer — Date

Approved by: James C. Linville — 1/12/88
James Linville, Chief, Projects Section 2A — Date

Summary: Routine daytime (178 hours) and backshift (16 hours including weekends) inspections of Unit 1 by the resident inspectors consisting of (a) resolution of outstanding items including response to NRC Bulletin 87-02 on fasteners; (b) walkdown of the Redundant Reactivity Control System (RRCS), plant tours, and observations of maintenance and surveillance; and (c) review of LERs and periodic reports.

Events followed included several reactor enclosure isolations during the period and a feedwater level transient on November 19. The inspectors noted that prompt reactor operator response to the feedwater transient prevented a reactor scram and reflects well on simulator training. Meetings attended included routine Plant Operations Review Committee (PORC), Electro Hydraulic Control System (EHC) evaluations, a Unit 2 SALP meeting on December 7 and a Nuclear Review Board (NRB) meeting on December 10.

One violation was identified (Detail 3.2.1) concerning isolation of fire water suppression valves without appropriate supervisory authorization. Two licensee identified violations involving surveillance testing are discussed in Detail 5.2.2. An example where the licensee's activities in the assurance of quality were not effective in correcting internal panel wiring errors as well as notable examples of effective worker performance and management critique of personnel errors, are discussed in Detail 8.

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
J. Grimes, Branch Engineer, Testing and Labs
J. Milito, Field Engineer
D. Helwig, QA Manager
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 NRC Bulletins and Unresolved Items

2.1 NRC Bulletin No. 87-02; Fasteners

In response to NRC Bulletin 87-02, Fastener Testing to Determine Conformance with Applicable Material Specifications, the licensee began planning for selecting a sample of fasteners to be tested as required by action number 2 of the bulletin. The inspector reviewed the selection process being used to ensure a diverse sample of various grades and sizes of fasteners. The inspector also verified that the licensee selected the sample in approximate proportion to the in-plant use of each type of fastener. The inspector noted consistent communications between the licensee's Unit 1 and Unit 2 organizations so that there is no duplication and a minimal amount of overlap in the types of fasteners to be tested.

The final selection of specific fasteners to be tested and subsequent test results will be reviewed by the inspector in a subsequent report.

3.0 Plant Operations

3.1 Summary of Events

Unit 1 was limited to operation at 85% power until November 21. Main turbine electrohydraulic control system instabilities were eliminated on November 21 by installation of a notch filter which enabled operation at 99% power. An instability of the number 3 main turbine control valve, requiring adjustment of a function generator card, prevented full licensed power from being achieved until the

end of the inspection period. A feedwater level transient occurred on November 19 (Detail 4.2).

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 procedures and compliance with technical specifications. The inspectors reviewed shift superintendent, control room supervision, and licensed operator logs and records covering the entire inspection period. On December 8 and 10, backshift inspections were performed between the hours of 2:00 am and 6:00 am.

The inspectors reviewed logs and records for completeness, abnormal conditions, and significant operating changes and trends. Other records reviewed included: reactor engineer and shift technical advisor (STA) books, night orders, radiation work permits, the locked valve log, maintenance request forms, temporary circuit alterations, and ignition source control checklists. The inspectors also observed shift turnovers during the period. Operations activities were observed to be in conformance with Administrative Procedure A-7, Conduct of Plant Operations, with the exception of the removal from service of fire equipment described below.

On November 16, a reactor operator issued blocking permit number 7025 to isolate hose reel number 119 in the turbine enclosure for repairs. The permit closed header isolation valves 0058 (normally open) and 1106 (normally locked open) resulting in the isolation and inoperability of 17 fire hose stations and fire suppression water to the standby gas treatment and control room emergency fresh air system filters. The reactor operator failed to obtain shift supervision review and approval of the permit as required by the plant administrative procedure. Fire protection equipment was rendered inoperable without implementing compensatory measures. Administrative procedures for the control and operation of locked valves were also violated.

The isolation valves were closed from 1:00 a.m. until 5:15 a.m. at which time the shift supervisor became aware of the evolution and directed the valves be reopened. The failure to follow Administrative Procedures A-8 for the control of locked valves and A-41 for removing technical specification equipment from service is a violation of Technical Specification 6.8.1 which requires the implementation of procedures for the control of plant equipment (50-352/87-28-01).

As discussed in section 8.2 of this report a PORC meeting was held to review this and various other instances of personnel error in an effort to identify and correct any root causes which may be contributing to a higher error rate.

3.2.2 Security

During entry to and egress from the Unit 1 protected area and vital areas, the inspectors observed that access controls, security boundary integrity, search activities, escorting and badging were in accordance with Security Plan implementing procedures and guard force instructions. The inspectors also observed the availability and operability of security systems such as search equipment, perimeter detection devices, and security computer alarms. The inspectors verified that the minimum number of armed guards required by the Security Plan to be onsite were present on selected shifts by review of duty rosters, discussion with licensee Shift Security Advisors, and observation of guard force turnovers. No violations were identified.

3.2.2.1 Guard Force Drug Testing

The inspector was informed by licensee security management of a Protection Technology Inc. security force member whose employment was terminated on November 18 for drug use. The individual had been a watchman on the Unit 1 guard force for the past 20 months. During routine drug screening which was part of the watchman's annual physical on November 12, the physician conducting the testing noticed an unusual clarity and low pH of the individual's urine sample. A second test sample was taken and the results (using gas mass chromotography techniques) indicated positive for cocaine byproducts. The watchman's Unit 1 protected area access was restricted on November 12, an employment termination interview was conducted on November 18, and the Nuclear Employee Data System was notified.

3.2.2.2 Drug Investigations

As a result of ongoing drug investigations on site, negative drug test results were received for four janitorial personnel tested on November 6. An additional person was interviewed on November 9, admitted to drug use, and had his employment terminated. Positive test results were received for a sixth janitor, badged for Unit 1 protected area access since September 1987, who admitted to recent marijuana use offsite.

Licensee investigators interviewed another janitor on November 12 implicated during the investigation as a potential drug dealer. That individual admitted to cocaine sales. Some were inside of the Unit 1 protected area but principally were from

his vehicle in the parking lot. The sales were primarily to laborers and other janitorial personnel. The individual who admitted to selling cocaine had been badged for Unit 1 access for approximately three years and had stated that he was not a user. His employment was terminated by his onsite employer on November 13 and, his name was provided to local law enforcement authorities. Additional interviews of that individual by licensee investigators are planned.

The resident inspector was apprised of the above information by the licensee on November 13 and November 16, and determined that the licensee's actions were in accordance with the PECO fitness for duty program.

3.2.3 Radiological Controls

The inspectors observed the availability and use of radiation monitoring equipment, including portal monitors and portable friskers. The inspectors also observed health physics (HP) supervision and technicians in plant activities involving potentially significant radiological conditions. Radiation work permits (RWPs) were selectively reviewed to determine that appropriate job controls, protective clothing, dosimetry and HP support were prescribed, in use, and understood by workers involved.

Radiological controls for posted radiation and contaminated areas were assessed as part of the inspector review of selected RWPs. Proper surveys and contamination clothing were prescribed. Radiological conditions were discussed with HP technicians. Proper locked high radiation area controls, including appropriate and frequent surveys, were verified to be employed. The inspector had no further concerns, and identified no violations.

3.3 Station Tours

The inspectors toured accessible areas of the plant throughout the inspection period, including: the Unit 1 reactor and turbine-auxiliary enclosures, the main control and auxiliary equipment rooms; battery, emergency switchgear and cable spreading rooms; the spray pond pumphouse; diesel generator cubicles and the plant site perimeter. During these tours, observations were made of potential fire hazards, radiological conditions, housekeeping, tagging of equipment, ongoing maintenance and surveillance, and the availability of required equipment. No unacceptable conditions were identified.

3.4 Safety System Operability

3.4.1 RRCS Verification

The inspector performed a detailed walkdown of the redundant reactivity control (RRCS) system in order to independently verify system operability. The walkdown included review of the following:

-- Technical Specifications, Final Safety Analysis Report (FSAR) Sections, P&IDs, and Licensed Operator Training Plans.

-- RRCS equipment conditions

-- Status of control room indicators and controls

-- Complete surveillance tests.

The inspectors discussed recent maintenance, modifications, and design concerns related to the RRCS with responsible reactor and I&C engineers. Proper operation of the RRCS was also verified from a review of the post-trip alarm log and the sequence of events printout from the September 19, 1987, reactor scram event.

No unacceptable conditions were noted.

3.4.2 PRA-Based Inspection of HPCI

The inspector performed a high pressure coolant injection (HPCI) system walkdown 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 incorporates abbreviated system checklists which contain components that are considered to have a high contribution to risk as determined in the PRA.

The inspector verified the proper operability or configuration of the following HPCI system components on several occasions during the inspection period:

-- pump suction from CST
-- lube oil cooling supply
-- steam supply isolation valves

-- turbine exhaust vacuum breakers
-- overspeed trip logic

No unacceptable conditions were noted.

3.5 Quality Group Findings

On August 31, the Unit 2 NRC resident inspector identified numerous wiring errors in the Unit 2 Power Generation Control Complex (PGCC) panels. Unit 2 PECO QC was made aware of the finding and began investigating to determine the extent and cause of the incorrect wiring. Unit 2 PECO QA subsequently informed the Unit 1 Operations Quality Control department, however the initial actions taken did not appear to be adequate to fully identify the extent of the problem on Unit 1 and the plant operations department management was not appraised of the problem until prompted by the Unit 1 Senior Resident Inspector. A subsequent inspection of a sample of Unit 1 PGCC electrical panels identified numerous deficiencies. The two types of discrepancies identified were :

1) inactive electrical leads which were not properly insulated and secured in the panel, and
2) vendor leads which are incorrectly identified.

The licensee field engineering group is reviewing the leads and, to-date, has found that the leads were inactive in accordance with an approved plant modification. However, the inactive leads should have had the lugs cut off, heat shrink insulation installed, and should have been secured in the wire bundle. All of the PGCC panels are to be inspected for this type of deficiency and corrected.

A Plant Operations Review Committee (PORC) was convened on December 8 to review the results of the inspection and the potential impact of the discrepancies on the safe operation of Unit 1. The PORC determined that based on the satisfactory completion of blue tag, preoperational, and surveillance testing and the fact that the electrical panel inspection did not confirm any actual miswiring, continued operation of Unit 1 was warranted and no unsafe condition existed. PORC did request development of a plan by field engineering for final resolution of the problem of mislabeled vendor leads. The inspectors will follow the results of the licensee's review.

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 Secondary Containment Isolations

An isolation of the reactor enclosure occurred on November 6, followed by expected initiation of the standby gas treatment system (SGTS). The cause was a loss of secondary containment differential pressure. This was due to misalignment of air supply isolation valves because incorrect operational aids were attached to the valves. A similar problem occurred on October 24 and, to avoid recurrence, the licensee applied operator aids (notes) to the valves. The notes were attached to the wrong isolation valves, such that operators incorrectly aligned the air supply system. The systems were properly reset and the operator aids were corrected.

Another isolation of the reactor enclosure occurred on November 14 followed by the expected initiation of the SGTS and reactor enclosure recirculation (RERS) systems. The cause was a loss of differential pressure when the operating alignment of the reactor enclosure exhaust fans was changed from 'B' and 'C' fans operating to 'A' and 'C' fans operating. Due to system performance problems, the 'A' and 'C' fan combination is currently not able to maintain the required differential pressure. The SGTS and RERS functioned as designed, the isolation was reset, and normal ventilation was restored.

A third set of reactor enclosure isolations occurred twice on November 21 due to a low differential pressure signal. In both cases, the low pressure was due to ventilation supply and exhaust fan trips on low supply air temperature. The low temperature was caused by initiation of a turbine enclosure supply fan which resulted in reduced steam flow to the supply fan heating coils. Turbine enclosure heating coil steam flow was abnormally high at the first isolation due to both the temperature control valve and its bypass valve being open when the fan was restarted, thus starving the reactor enclosure heating coil. Low air temperature in the second isolation was due to an auxiliary boiler trip. In both cases, all systems started as designed.

The inspectors confirmed proper system response and appropriate ENS notification in all above isolations.

4.2 Feedwater Level Transient

A reactor water level transient occurred on November 19 due to a loss of one feedwater pump and a failure of a master level controller, causing the other two feedwater pumps to increase speed. Reactor water level increased to +53 inches (one inch below the high turbine trip setting). A licensed operator quickly recognized the event and took manual control of the remaining pumps, and the resulting decrease in level was limited to +17 inches (five inches

above the low level scram set point). Reactor power decreased from 85% to 44%, due in part to a recirculation pump run back to 28% flow.

The cause of the level transient was an error by a nonlicensed operator who, when applying a block to a non-Class IE auxiliary boiler circuit, had his hand slip which opened a breaker feeding power to feedwater and recirculation pump control circuits. In addition to the loss of master feedwater controls and recirculation flow inputs, certain nonsafety-related alarm circuits and indications were also lost. Normal reactor vessel level was stabilized within minutes, the breaker was reclosed, and power ascension was commenced approximately one hour later. Reactor power was returned to 85% the same day. The inspector confirmed proper system responses, operator adherence to procedures, and management overview of recovery activities.

4.3 Security Computer Outage

The Unit 1 security computer failed on December 6 due to a secondary disc drive malfunction. Compensatory coverage of vital areas was achieved within 10 minutes for all but one room. A designated force member arrived at the rear corridor door of a room in the control enclosure with the wrong key. Upon realizing that the key was incorrect, the guard returned to the key issuance area, obtained a correct key, but arrived back at the door in question approximately 12 minutes after the computer failure. Sweeps of all vital areas were completed, vital key inventories were confirmed, the security computer was returned to service and the NRC was appropriately notified via the ENS.

The computer failure also resulted in a violation of technical specification firewatch compensatory requirements. The inability of the normal firewatch person to gain access to an area (following the computer failure) resulted in exceeding the required hourly time interval by 17 minutes in the area.

When the firewatch could not gain access to the area, security was contacted and dispatched a guard to open the door. However, the guard had the incorrect key which resulted in exceeding the hourly interval.

The reason for assigning incorrect keys appears to be due to the periodic key core changeout which was recently accomplished. Key numbers are also rotated along with lock cores which contributed to the selection of incorrect keys. The inspectors determined that the security force supervisor assigning keys failed to use procedures which have been properly updated and, instead, provided keys for the compensatory responders from memory. The inspectors will follow the

licensee's subsequent description of the above events, including corrective measures proposed, in the required reports to be submitted to the NRC.

5.0 Licensee Reports

5.1 In-Office Review of Licensee Event Report

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 the description of the cause and the adequacy of the corrective action. Where multiple causes are suspected, or may be different than reported in the LER, this is indicated below. 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 and Date	Subject	Root Cause
87-53 10/26/87	Incomplete Rod Worth minimizer (RWM) surveillance test	Deficient Procedure
87-54 10/28/87	Late scram discharge volume surveillance test	Incorrect test date scheduled due to personnel error
87-55 11/18/87	Appendix R License Condition violation	Inadequate design review
87-56 11/16/87	Secondary containment isolation and initiation of SGTS and RERS on low reactor enclosure pressure	Auxiliary boiler failure (dirty torch tip), loss of auxiliary heating steam, and supply fan trip
87-57 11/16/87	Control room isolation and Control Room Emergency Fresh Air System (CREFAS) initiation during troubleshooting	Inadequate instruction of I&C technicians concerning radiation monitor bypass switch
87-58 11/19/87	Secondary containment isolation and SGTS/RERS initiation on low reactor enclosure pressure	Auxiliary boiler trip on high steam flow (cause unknown), and loss of auxiliary heating steam to supply fans/dampers

87-59 12/2/87	Secondary containment isolation and SGTS/RERS initiation on low reactor enclosure pressure	Inadequate block applied to air compressor, leaking check valve, and loose damper air valve fittings
87-60 11/25/87	Secondary containment isolation and SGTS/RERS initiation on low reactor enclosure pressure	Incorrect instrument air valve closed due to personnel error and mislabelled valve

LER Nos. 87-56 through 60 were previously addressed in Detail 4 of Inspection Report 50-352/87-24.

LER Nos. 87-53, 54, 59 and 60 are addressed in Detail 5.2 of this report.

LER No. 87-55 is addressed in Inspection Report No. 50-352/87-27.

5.2 Onsite Followup of Licensee Event Reports

For those LERs selected for onsite followup, 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 facility was conducted in accordance with Technical Specification limits.

5.2.1 LER No. 87-53; Incomplete RWM Surveillance

During a reduction in reactor power on September 26, the rod worth minimizer (RWM) began automatically enforcing control rod motion at 25% power, as designed. Within eight minutes after reaching that point, surveillance test (ST)-6-073-320 was performed to verify proper RWM indication of a control rod selection error. Approximately eight hours later, the individual assigned to review completed test procedures identified a portion of the RWM test involving the Select Error light which had not been performed because of a missing page in the procedure. The verification of proper RWM indication, required within one hour following automatic initiation of the RWM, was a licensee-identified violation of technical specifications (50-352/87-28-02).

The inspector concluded that the violation met the criteria of the NRC's Enforcement Policy to self-identified findings, and that no Notice of Violation would be issued, because the mistake has not been a recurrent problem and the minimal significance with

respect to reactor safety. The mistake existed for only eight hours and was promptly detected by the next shift. Subsequent operability of the RWM select error light was confirmed. Furthermore, reactor power at the time of the discovery of the incomplete test was 22%, and recent GE evaluations have concluded that a dropped rod accident (the design basis for the RWM) is only significant at power levels below 10-15% power.

Most significantly, the licensee's corrective action was extensive and should represent an improvement in the conduct of surveillance testing. Effective October 19, the licensee relieved the control room shift clerk from the responsibility of providing copies of test procedures to be conducted by operating staff. Instead, a more controlled and consistent method of updating the startup and shutdown procedure binders (used to obtain test procedures during those fast turnaround situations) will be assumed by the licensee's Nuclear Records Management group. The controlled copy binders will be maintained in the control room, and responsibility for completeness and update (including periodic audits) will be with that group. This action represents the culmination of an evolution of measures which will assure that, during rapid plant operational condition changes, important surveillance testing which can only be performed at those times is completed satisfactorily.

5.2.2 LER No. 87-54; Late SDV Surveillance Test

The inspector assessed an error made by an I&C test coordinator resulting in a functional test of a high scram discharge volume (SDV) water level switch being overdue by 17 hours. The switch enables a control rod block, and was later successfully tested. All other similar SDV switches were available and operable. Reactor power was at 12% at the time that the surveillance lapsed, and no control rod moves were being performed, nor were any high level alarms present.

The inspector concluded that no citation would be issued for this licensee-identified violation (50-352/87-28-03) since it was not safety significant and not a recurrent problem. Appropriate reporting and corrective actions were accomplished. It is a notably consistent trait for licensee first-line supervision to review completed test procedures or impending test schedules and, as a result, identify errors which are then promptly corrected. In this particular case, planning for weekend work loads identified (two days ahead of the incorrect schedule) that the wrong due date had been assigned for ST-2-047-614-1. Sufficient staffing and supervision of test personnel, and a well-managed test program, enabled the

discovery of the overdue test. No other similar incorrect schedule entries were found, and the I&C group created a special tracking list for tests close to expiration of their surveillance interval. The inspector had no further concerns.

5.2.3 LER Nos. 87-59 and 60; Secondary Containment Isolations

The inspector noted that a thorough root cause analysis had been presented for the reactor enclosure isolations described in the subject LER's. The events were caused by a lack of a complete and accurate identification and tagging system for instrument air tubing and block valves, and a failure to assess the consequences of taking an air compressor out of service. Both LER's involved substantial interaction and discussion between site operating staff and corporate licensing engineers. As a result, comprehensive root cause determinations were made that enabled what appear to be corrective measures that will prevent additional instrument air problems and better correlate air supplies, loads and isolation valves. LER 87-60 describes modification number 5561 which is currently in progress to: (a) walkdown all instrument air lines; (b) revise P&ID's appropriately; (c) add additional or delete unnecessary instrument root/block valves; and (d) create unique valve tag numbers. LER 87-59 utilized a simplified sketch to describe the event. Both LER's detailed previous similar occurrences and, where necessary, correlated lessons learned. Both LER's were concluded by the inspector to be of high quality.

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 for the required information, that 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:

-- Revision to August and September 1987 Monthly Operating Reports, dated November 5

-- Monthly operating reports for October and November 1987

-- PECO letter to NRC (Fogarty to Russell) dated November 30, 1987; Summary Reports for ISI and ASME Repairs

-- PECO letter to NRC (Gallagher to Gallo) dated December 9, 1987; Response to Inspection 50-352/87-25 violation, MRF closeout

-- PECO letter to NRC (Gallagher to Gallo) dated November 9, 1987; Response to Inspection 50-352/87-19 violation, drawing control

-- PECO letter to NRC (Kemper to Butler) dated November 5, 1987; Additional information on LPCI license Amendment

-- PECO letter to NRC (Alden to Russell) dated November 16, CILRT Report

The inspector had no questions about the reports.

6.0 Surveillance Testing

6.1 Test Observation

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

-- ST-6-107-590; Daily Surveillance Log

-- ST-3-048-230-1; Standby Liquid Control Functional

-- ST-6-047-750-1; CRD Accumulator Weekly Pressure Check

-- ST-2-042-607-1; Monthly ECCS and Reactor Level Calibration

-- ST-6-092-311 and 312-1; Monthly D-11 and D-12 Diesel Run

-- ST-2-047-613-1; RPS Scram Discharge Volume Channel B High Level

-- ST-2-050-601-1; Divisions 1 and 3, ECCS/ADS Timer Calibration Pressure Test

-- ST-8-092-321; 4 kV Emergency Safeguard Bus Undervoltage Check

-- ST-6-011-206-2; ESW Quarterly Valve Test

-- ST-6-057-200-1; Containment Atmosphere Control Valve Test

-- ST-6-049-230-1; RCIC Quarterly Pump Test

The tests were observed to determine that surveillance procedures conformed to Technical Specification requirements; testing was being performed in accordance with Administrative Procedures A-43 and 47; 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 within Technical Specification limits; and equipment was properly returned to service following testing.

No unacceptable conditions were noted.

7.0 Maintenance

The inspector observed selected maintenance activities on safety related equipment to ascertain that: the work was conducted in accordance with Administrative Procedures A-25, 26 and 27 using approved work instructions or procedures; proper equipment permits and tagging were applied; 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 # 8781774; HPCI Booster Pump Oil Change
-- MRF # 8708334; Division 3 Battery Charger Circuit Board Repair
-- MRF # 8781773; RCIC Pump Oil Change
-- MRF # 8707675; MOVATS Testing on HPCI Valve HV-55-1F008

No unacceptable conditions were noted.

7.2 HPCI Overspeed Trip Failure

On December 7, the high pressure coolant injection (HPCI) pump was taken out of service for preventive maintenance. The booster pump bearing oil was replaced under maintenance request form (MRF) 8781774 and in accordance with preventive maintenance procedure PMQ-500-006. Oil samples were obtained for routine analysis.

The inspector verified that administrative approval had been obtained and that an appropriate system tag-out was in place. During observation of the work the inspector noted that the licensee quality control (QC) inspector was present to observe those portions of the procedure identified as QC hold points. The QC inspector was knowledgeable of his responsibilities and the inspection requirements for this activity.

Following the completion of the work the pump was run as part of the retest and to complete the routine surveillance test requirements. During this run, overspeed trip problems were encountered at an actual turbine speed below the overspeed trip setpoint. This problem does not appear to be related to the maintenance activity and a subsequent pump run was satisfactory with no apparent cause for the overspeed trip mechanism malfunction identified. The licensee suspects the spurious trips may have been caused by dirt partially blocking one of the trip mechanism's hydraulic ports, and was subsequently flushed from the port. An oil sample is planned to be taken. The inspector will follow the licensee's investigation.

8.0 Assurance of Quality

8.1 Worker Performance During Maintenance

An instance of good job planning and control was noted during repair of the Division 3 battery charger on December 4 as observed and noted in Detail 7.1. Engineering support was evident by the presence of maintenance staff and field engineering personnel. Full QC coverage of the job was performed and the assigned inspector was knowledgable of work instructions, procedural requirements and battery design. The craft assigned to the repair were two first-class mechanics from the licensee's specialized battery maintenance group who, when observed and questioned, appeared well qualified and cognizant of battery operation and vendor recommendations.

The licensee obviously placed a high priority upon the repair of the battery charger, in part because of a general recognition by all involved parties of entry into an eight-hour technical specification action statement. However, the priority of the job as reflected by worker performance was also created by station management's cognizance of the risk importance of the batteries, particularly for station blackout concerns.

8.2 Management Involvement in Operations

Station management and shift supervision were observed to be involved in the critique and analysis of the fire suppression valve blocking error addressed in Detail 3.2.1. Meetings and discussions among shift superintendents and operations management were held and, as part of corrective action for the violation, a videotape was being developed to address Unit 1 administrative controls as they apply to risk reduction in routine plant operating activities. The videotape will involve 15 operators performing in short skits associated with fundamental duties such as fire program and equipment control concerns, stressing the themes of attention to detail, thought before action, and involvement of supervision.

The licensee also convened a special PORC meeting to review 20 recent personnel error events and correlate these with nine separate potential causes involving concerns with communications, shift experience and procedure deficiencies. The matrix developed by the PORC identified several general areas of weakness in the conduct of operations which were being addressed by station management as distinct PORC commitments. The inspector concluded that station management is continuing to recognize and resolve important safety problems and, as evidenced by the above, propose unique corrective actions which have general support among the operating staff.

8.3 Quality Findings Presentation

An example was noted where a number of Unit 2 panel wiring errors were found by a recent NRC inspection (Report 50-353/87-13) in August 1987 but were not aggressively pursued for potential impact upon Unit 1 design.

The Unit 2 errors were documented as licensee QC findings for Unit 2 construction/design. However, the relevance to Unit 1 panels was inadequately evaluated by operations QA or QC groups and, after over two months time, only a very small sample of Unit 1 wiring terminations were inspected. Moreover, the number of errors found were large enough to warrant an expanded sample but none was performed, initially. The errors were not described or communicated to Unit 1 station management until such time that NRC concerns were raised. As discussed in Detail 3.5, an expanded sample was then performed, the errors were evaluated and characterized by the PORC, and appropriate information was developed to enable a decision on the immediate safety significance of the problem for continued operation. Better communication among the various licensee quality groups is needed, as well as development of a sensitivity for immediate operational concerns and presentation of those findings to operational staff.

9.0 Scram Discharge Volume Capability (Multiplant Action Item B-58)

In 1980 during a routine shutdown at another BWR facility, about 40% of the control rods failed to insert on a manual scram signal. Followup of this event revealed a number of deficiencies with the scram discharge volume (SDV) headers. Multiplant Action (MPA) Item B-58 "Scram Discharge Volume Capability" was assigned by the NRC to track this issue. An NRC generic study, "BWR Scram Discharge System Safety Evaluation" dated December 1, 1980 provided criteria for correcting identified deficiencies in the SDV system.

NUREG-0991, the Limerick SER dated August 1983, states that NRC has reviewed the extent of conformance of the SDV design with the criteria of the generic safety evaluation. The Limerick design provides two separate SDV headers, with an integral instrument volume (IV) at the end of each header, thus providing close hydraulic coupling. Each IV has redundant and diverse level instruments (float sensing and pressure sensing) for the scram function attached directly to the IV. Vent and drain lines are separated and contain redundant vent and drain valves equipped with redundant solenoid pilot values. High point vents are provided. The NRC staff concluded the design of the Limerick SDV fully met the requirements of the NRC generic report and was acceptable.

NRC Temporary Instruction (TI) 2515/90 provides inspection guidance to ensure the SDV meets ge[illegible] requirements, and lists 11 criteria along with actions to be take[illegible] udit compliance with the requirements. The following sections list [illegible] criterion and discuss its disposition.

9.1 Scram Discharge Header Size (Criterion 1)

Criterion 1 specifies that SDV headers shall be sized in accordance with GE-OER-54 and shall be hydraulically coupled to the instrumented volumes in a manner to permit operability of the scram level instrumentation before loss of system function.

GE-OER-54 states the SDV header should be sized for a minimum of 3.34 gallons per control rod drive. The Limerick design specification provides for 3.34 gallons per control rod drive. In Inspection Report 352/87-13 the inspector evaluated the results of preoperational test P55.1 conducted in March 1984 to confirm the SDV as being 634.8 gallons, which is more than the minimum required 618 gallons. The SDV capacity does not include volumes associated with vent and drain lines or the instrument volumes and connecting pipe.

The SDV header, an eight inch diameter pipe, is connected to the instrument volume, a 10 inch diameter pipe with a short eight inch diameter line. SDV pipe and connections to the IV slope downward to ensure draining. There are no reductions in pipe size from the HCUs to the SDV-IV. Therefore hydraulic coupling is ensured.

As the IV starts to fill, level instruments trigger an alarm or scram before the SDV header begins to fill. This ensures the scram header is able to accept the water. The inspector examined the SDV piping and connections, and no problems were noted. SDV headers appear to be adquately sized and hydraulically coupled to the IV.

9.2 Automatic Scram on High SDV Level (Criterion 2)

Criterion 2 states that level instrumentation shall be provided for automatic scram initiation while sufficient volume exists in the SDV.

In Inspection Report 352/84-01 the inspector verified the existence of two diverse means of water level indication for each IV that interfaces with the reactor protection system to cause a high IV water level scram. This scram will be initiated while sufficient volume exists in the SDV to accept the discharrged water.

9.3 Instrument Taps not on Connected Piping (Criterion 3)

Criterion 3 states that instrumentation taps shall be provided on the vertical IV pipe, and not on the connected piping.

FSAR question 410.20 states that all instrumentation taps for the IV are located on the vertical IV and not on connecting pipe. The inspector visually verified this to be true.

9.4 Detection of Water in the IV (Criterion 4)

In accordance with Criterion 4, scram instrumentation shall be capable of detecting water accumulation in the IV assuming a single active failure in the instrumentation system or the plugging of an instrument line.

In Inspection Reports 352/84-01 and 352/87-13 the inspector verified the existence of redundant and diverse means of detecting water level for each IV to cause a high level scram. Two differential pressure transmitters and two float switches are employed in each IV scram circuit. The two IVs are hydraulically coupled via a common drain line.

The inspector reviewed the FSAR, technical specifications and plant drawings to confirm an automatic scram function exists for high IV water level. The instrumentation is diverse and satisfies the single failure criterion. If a single failure should occur, there is sufficient redundancy to ensure that the instruments would respond properly.

9.5 Vent and Drain Valves System Interfaces (Criterion 5)

Vent and drain functions shall not be adversely affected by other system interfaces. The objective of Criterion 5 is to preclude water backup in the scram IV, which could cause a spurious scram.

The inspector reviewed the FSAR and drawings M-47, M-53 and M-62. The SDV drain line discharges into the equipment drain collection tank (EDCT). The SDV vent line discharges to dirty radwaste and is protected by a vacuum breaker (PSV-120). Redundant isolation valves on the vent and drain lines are normally open and would not prevent draining these lines in the non-scrammed condition. The inspector noted that FSAR question 410.20 erroneously states the vent lines discharge to the EDCT. This observation was discussed with licensee representatives who indicated FSAR changes would be made.

The two-inch drain line from the SDV-IV connects to the reactor well seal rupture drain line, an eight-inch line which discharges into the 25,000 gallon capacity EDCT. The tank has an overflow line to dirty radwaste. A rupture of both refueling cavity inflatable seals could cause the EDCT to overflow and flood the radwaste building floor. The water should not backup into the IV because of elevation differences between the IV, the drain tank, and the radwaste building floor.

Neither the vent nor drain function would be adversely affected by other system interfaces. Based upon an examination of visible portions of the vent and drain systems, review of appropriate drawings, and documentation, no unacceptable condition were noted.

9.6 Vent Drain Valves Close on Loss of Air (Criterion 6)

Criterion 6 addresses closure of the power-operated vent and drain valves under loss of air and/or electric power. Valve position indication shall be provided in the control room.

The inspector reviewed drawing M-47 and the appropriate FSAR discriptions and examined the vent and drain valves. The vents and drains are air operated air-to-open and spring-to-close valves which fail closed under loss of air and/or electric power. Valve position indication is provided in the control room, in accordance with Criterion 6.

9.7 Operator Aid (Criterion 7)

Instrumentation shall be provided by Criterion 7 to aid the operator in the detection of water accumulation in the IV's before scram initiation.

The inspector reviewed plant drawings and visually verified that an alarm exists in the control room. Level switches on each IV sound an alarm in the control room when the level reaches five gallons. The annunciator response card instructs the operator to enter operational transient procedure OT-105, which requires verification that all vent and drain valves are open. A controlled shutdown is initiated if the SDV-IV cannot be drained. Lights in the control room indicate valve position.

Based upon this inspection it is concluded that instrumentation and procedures are provided to aid the operators in detection of water in the IV before scram initiation.

9.8 Active Failure in Vent and Drain Line (Criterion 8)

Vent and drain line valves shall be provided to contain the scram discharge water with a single active failure and to minimize operational exposure, in accordance with Criterion 8.

Redundant SDV vent and drain valves are provided to ensure that no single active failure can result in an uncontrolled loss of reactor coolant. Redundant solenoid-operated pilot valves control the vent and drain valves. The valves fail in the closed position.

The inspector verified the valves were as described in the FSAR by visual observation and review of drawings. Procedure GP-11, Reactor Protection System-Scram Reset, requires a radiation survey of the SDV prior to releasing the fluid inventory if fuel damage is suspected. The licensee indicated the SDV is routinely monitored after all scrams. Radiation surveys of the SDV area are performed weekly.

9.9 Periodic Testing of Vent and Drain Valves (Criterion 9)

In accordance with Criterion 9, vent and drain valves shall be periodically tested.

Technical Specification 4.1.3.1.1 requires periodic testing of the vent and drain valves. Demonstration of operability verifies each valve to be open at least once per 31 days, and operating each valve through at least one complete cycle of full travel every 92 days. Technical Specification Table 3.6.3-1 indicates maximum closing times as:

F010 inner vent	25 seconds
F011 inner drain	25 seconds
F180 outer vent	30 seconds
F181 outer drain	30 seconds

In Inspection Report 352/84-01, the inspector verified the existence of testing procedures to show the operability of the SDV vent and drain valves. The procedure is ST6-047-200-1 "SDV Valve Exercise Test" performed quarterly. The maximum closing time is measured in the surveillance test.

9.10 Periodic Testing of Level Detection Instrumentation (Criterion 10)

Level detection instrumentation and verifying level detection instrumentation shall be periodically tested in place.

Technical Specificaiton 4.1.3.1.4 requires that SDV level instruments be periodically tested in place. A channel functional test of the rod block and scram level instruments is required every 31 days. Technical Specification Table 4.3.1.1-1 requires the scram instruments to be calibrated each 18 months. The following surveillance tests satisfy Criterion 10:

Test	Level Instrument	(Months) Frequency
ST-2-047-407 thru 410	LT-47-IN012A thru D; LISH-47-IN601A thru D 18	18
ST-2-047-612-1	LSH-47-IN013A	1
ST-2-047-602-1	LSH-47-IN013C	1
ST-2-047-603-1	LSH-47-IN013D	1
ST-2-047-613-1	LSH-47-IN013B	1
ST-2-047-608 thru 611	LISH-47-IN601A thru D	1
ST-2-047-614 and 615	LSH-47-IN013E	1

The inspector concluded that appropriate surveillance tests exist that incorporate restoration steps including independent verifications of status.

9.11 Periodic Testing Operability of the Entire System (Criterion 11)

The operability of the entire system as an integrated whole shall be demonstrated periodically and during each operating cycle by demonstrating scram instrument response and valve function at pressure and temperature at approximately 50% control rod density.

Technical Specification 4.1.3.1.4.a requires the system to be demonstrated operable when control rods are scram tested from a normal control rod configuration of less than or equal to 50% rod density at least once per 18 months. Procedure ST-3-047-320-1, "SDV Operability on Scram" implements this requirement. The inspector reviewed ST-3-047-320-1 performed on 5/2/86, 1/27/87 and 5/18/87. No unsatisfactory conditions were noted.

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 on December 7, 1987 and again with the Superintendants of Operations and Services on December 10, 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.

NRC Form 766 U. S. NUCLEAR REGULATORY COMMISSION

Principal Inspector.
Kelly, Gene
Reviewer: J. Linville

INSPECTOR'S REPORT

Office of Inspection and Enforcement

Inspectors:	Transaction Type:	Docket #/Inspection #/Seq #		
E. Kelly				
L. Scholl	* I-Insert	05000352	87-28	A
	M-Modify			
	D-Delete			
	R-Replace			

Licensee/Vendor:
Philadelphia Electric Co.
Attn: Mr. J. Gallagher
V. P Nuclear Services
2301 Market Street
Philadelphia, PA 19101

Period of Inspection: From	To	Inspection Performed By:	Organization Code of Reg.: Region	Division	Branch
		1-Regional Office Staff			
		* 2-Resident Inspector	I	B	B
11/01/87	12/10/87	3-Performance Appr.Team			
		-Other			

Regional Action:
1 - NRC Form 591
*2 - Regional Office Letter

Type of Activity Conducted (* one only):

* 02-Safety	07-Special	12-Shipment/Export
03-Incident	08-Vendor	13-Import
04-Enforcement	09-Mat. Acct.	14-Inquiry
05-Mgnt. Audit	10-Plant Sec.	15-Investigation
06-Mgnt. Visit	11-Invent. Ver.	

Total No. of Violations and Deviations:	Enforcement Conference Held:	Report Contains 2.790 Information:
01		

Inspection Findings:

A	B	C	D	
				- Clear
X				- Violation
				- Deviation
				- Violation & Deviation

Letter or Report Transmittal Date

NRC Form 591 or Region Letter Issued:

Report Sent to HQ for Action:

TRANSMITTAL COPY 1/14/88

INSPECTOR'S REPORT

(Continuation)

Docket No. 05000352 Report No. 87-28 Seq. A Module Number 71707
Violation Severity IV

As a result of an inspection conducted on November 1 - December 10, 1987, and in accordance with the General Statement of Policy and Procedure for NRC Enforcement Actions, 10 CFR Part 2, Appendix C (1987), the following violation was identified:

Technical Specification 6.8.1 requires that plant procedures be implemented, including those procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, for administrative control of plant equipment.

Administrative Procedures A-8 and A-41 provide measures for the control of locked valves and the removal from service of equipment required to be operable by the Technical Specifications, respectively. Step 5.1 of both procedures A-8 and A-41 requires shift supervision permission to change locked valve position or the release of equipment for maintenance.

Contrary to the above, on November 16, 1987, fire suppression water isolation valves numbered HV-022-1106 and 0058 were unlocked and closed from 1:00 am to 5:15 am without shift supervision permission. This resulted in the isolation and inoperability of 17 fire hose stations and safety-related ventilation system filters without the establishment of compensatory firewatches and substitute fire hose water sources.

This is a Severity Level IV violation. (Supplement I)

NRC Form 766 - Continued

MODULE INFORMATION

Record / Module No.	Direct Insp. Hours	Percentage Complete	Status	Module Followup
B 530703	10			
B 571707	80	100		
B 25590	25	100	C	
B 561726	20	100		
B 562703	15	100		
B 571710	9	100		
B 590712	4			
B 592700	5			
B 590713	2			
B 593702	4			
B 571881	5	100		
B 571709	5	100		
B 525026	10	20		

NRC Form 6 Rev. Dec. 86

OUTSTANDING ITEMS FILE SINGLE DOCKET ENTRY FORM

Docket Number: 50-352
Originator: Kelly, Gene

Reviewing Supervisor: Linville, James

Report Hours:				
1. Operations	83	7. Outages	0
2. Rad-Con	8	8. Training	0
3. Maintenance	18	9. Licensing	0
4. Surveillance	23	10. QA	14
5. Emerg. Prep.	4	11. Other(Engineering)	35
6. Sec/Safegrds.	9	12. Fire Protection/ Housekeeping	

Item Num.	Type	SALP Area	OI Area	Action Due	Updt/Clsout Rpt	Date	O/M/Cls
87-28-01	NC4	Operations	PSC	04/05/87		12/10/87	O

Originator: Kelly
Modifier/Closer:
Descriptive Title: FAILURE TO FOLLOW ADMINISTRATIVE PROCEDURE A-8 and A-41

Item Num.	Type	SALP Area	OI Area	Action Due	Updt/Clsout Rpt	Date	O/M/Cls
87-28-02	NV4		PSC		87-28C	12/10/87	O C

Originator: Kelly
Modifier/Closer:
Descriptive Title:

Item Num.	Type	SALP Area	OI Area	Action Due	Updt/Clsout Rpt	Date	O/M/Cls
87-28-03	NV4		PSC		87-28C	12/10/87	O C

Originator: Kelly
Modifier/Closer:
Descriptive Title: