U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 86-03

Docket No. 50-352

License No. NPF-39 Priority -- Category C

Licensee: Philadelphia Electric Company

2301 Market Street

Philadelphia, Pennsylvania 19101

Facility Name: Limerick Generating Station, Unit 1

Inspection Conducted: January 11-February 28, 1986

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

Reviewed by: J E Beall 4/8/86
J. E. Beall, Project Engineer Date

Approved by: Robert M. Gallo 4/8/86
R. M. Gallo, Chief, Reactor Date
Projects Section 2A

Inspection Summary: Inspection Report No. 50-352/86-03 for Inspection Conducted January 11-February 28, 1986

Areas Inspected: Routine and backshift inspections by the resident inspectors consisting of followup on outstanding items; observation and review of TC-6 startup testing; system walkdown of the Standby Liquid Control system; STA training; plant tours including fire protection measures and nitrogen inerting; maintenance and surveillance observations; and review of LERs and periodic reports. Events which occurred during the period, and were reviewed, include: reactor scrams on January 13 and February 10; and miscalibration of feedwater flow transmitters which amounted to a 0.6% underestimate of computer calculated core thermal power.

Results: Three unresolved items were identified, associated with trouble-shooting and test meter control (Detail 4.2), sump sampling techniques (Detail 4.3), and toxic gas analyzers (Detail 5.2.2). No violations were identified. This inspection involved 207 hours of onsite inspection of Unit 1.

DETAILS

1.0 Persons Contacted

Philadelphia Electric Company

J. Doering, Operations Engineer
R. Dubiel, Senior Health Physicist
P. Duca, Technical Engineer
J. Franz, Superintendent of Operations
A. Jenkins, GE Startup Manager
G. Leitch, Station Manager

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) BNL Review of ESW Instrument Recalibration Program

A Technical Review of the Emergency Service Water (ESW) system performed by Brookhaven National Laboratory (BNL) for NRC Region I and issued to PECO by letter dated October 4, 1984 identified an open item associated with completi n of a recalibration program for ESW panel-mounted meters in the main control room.

The inspector reviewed the licensee's November 7, 1984 response to NRC regarding the recalibration cycle for ESW gages located on main control panel C667. The inspector verified that all instruments in ESW system on the M-11 P&ID for flow, temperature and pressure as well as pump motor ammeters were entered in the licensee's engineering data base associated with the computerized history and maintenance program system (CHAMPS). The instruments used as part of Technical Specification surveillance tests or safety related procedures had 18 month to 2-year recalibration schedules; the pump motor ammeters were scheduled for a 3-year recalibration; and, the temperature indicators had a 7-year frequency.

The calibrations of all ESW instrumentation were verified to be current, the selection and frequency were evaluated and found to be reasonable based on experience, and the BNL item is therefore considered closed.

2.2 License Condition - Nitrogen Inerting System Modifications

The inspector reviewed modification package MDCP-493 which implemented changes to the nitrogen vaporization and supply system in accordance with a condition to the full power license, Attachment 1, which was required to be completed prior to initially inerting containment.

The inspector: (1) reviewed operating procedure S57.8.A used to place the vaporizing system in service; (2) evaluated test results ST-2-057-410, 411, 412 and 600 to calibrate the associated protective logic added to the vaporizer; (3) reviewed the maintenance packages and post-maintenance test results to install the ambient vaporizer and associated equipment; (4) observed the operation of the modified nitrogen vaporization skid; and (5) discussed the modification with the responsible nitrogen system test engineer.

The modification was completed in October 1985 and the NRC was informed of the completion by the licensee in a letter dated November 22, 1985. The inspector verified that the modifications were in-place and operable prior to the initial containment inerting performed in January 1986 (see Detail 3.2.1), and concluded that the requirements of this license condition had been met.

3.0 Review of Plant Operations

3.1 Summary of Events

The plant operated at full rated power through most of the inspection period. The startup test program was completed, and commerical operation was declared on February 1, 1986, following performance of the 100-hour warranty run on January 23-28, 1986.

A planned manual scram was initiated on January 13, 1986, due to the discovery of a main turbine control valve which would not fully close. The scram is addressed in Detail 4.1. The valve repair, addressed in Detail 6.1, resulted in the plant being shut down for six days. Startup test activities in Test Condition 6 were resumed on January 21 and active testing was finished upon completion of the 100-hour warranty run at 2:00 a.m. on January 28. Test results were evaluated and approved, and the Startup Test Program was ended on January 31 and commerical operation was declared on February 1.

A discrepancy of approximately 0.6% in calculated core thermal power was discovered during the STP-20.1 warranty testing. The discrepancy was attributed to a feedwater flow calibration error and amounted to an underestimate of about 21 MW in process computer thermal power calculations. The discrepancy caused an estimated 138 hours of reactor operation above the licensed thermal power limit of 3293 MW during the period December 26, 1985 - January 29, 1986. Warranty testing, including an evaluation of the feedwater flow calibration error, is discussed in Detail 7.2.

Primary containment inerting had been deferred until either full power startup trip testing was completed or until 120 effective full power days of reactor operation had elapsed. Testing involving the "B" recirculation pump (STP-30.1) and the "C" reactor feedwater pump (STP-23.5) was completed on January 22, and calculated core exposure was approxinmately 60 effective full power days at that time. Preparations to inert primary containment atmosphere with nitrogen were begun during this inspection period. The required technical specification oxygen concentrations (less than 4% by volumne) in the drywell and suppression pool air spaces were initially achieved on January 19, and are discussed in Detail 3.2.1.

An unplanned scram occurred on February 10, 1986 from 99.8% power on a high flux signal. The high flux was the result of a pressure increase from turbine control valve closure due to a momentary ground created in the main turbine pressure control system by a test engineer who had been collecting turbine operating data. The scram is addressed in Detail 4.2. The reactor was restarted on February 11 and operated at full power through the end of the inspection period.

3.2 Operational Safety Verification

The inspector toured the control room daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. 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 releases. Panel indications for onsite/offsite emergency power sources were examined for automatic operability. During entry to and egress from the protected area and vital island, the inspector observed access control, security boundary integrity, search activities, escorting and badging, and availability of radiation monitoring equipment including portal monitors. No unacceptable conditions were found.

The inspector reviewed shift superintendent, control room supervisor, and operator logs covering the entire inspection period. Sampling reviews were made of equipment trouble tags, night orders, and the temporary circuit alteration and LCO tracking logs. The inspector also observed shift turnovers during the period. The operations activities were observed for conformance with the applicable procedures and requirements; no unacceptable conditions were noted.

3.2.1 Initial Containment Inerting

A special test exception in Technical Specification 3.10.5 allowed operations during the startup test program without an inerted containment, at less than 4% oxygen concentration. The exception applied until either full power testing was complete or the reactor had exceeded 120 effective full power days of operation.

The inspector verified that, at the time of completion of the recirculation and feedwater pump trip tests (STP-30.1 and 23.5) on January 22, 1986, the calculated core exposure was approximately 60 effective full power days. The licensee began preparations to inert earlier in the month, and achieved the required Technical Specification oxygen concentrations in the drywell and suppression pool air spaces on January 19, 1986. The licensee operated the nitrogen supply system at 1300 scfm and reduced oxygen concentration from 21 to 3.5% in 4-6 hours. The inspector periodically verified proper containment oxygen concentration throughout the remainder of the inspection period. The inspector also observed portions of the initial inerting activities, reviewed procedure S57.1.A used to inert the containment with nitrogen, and discussed nitrogen supply operations with the responsible system engineer. No unacceptable conditions were noted.

3.3 Station Tours

The inspectors toured accessible areas of the plant throughout this inspection period, including: the Unit 1 reactor and turbine-auxiliary enclosures; the main control and auxiliary equipment rooms; emergency switchgear and cable spreading rooms, diesel generator and radwaste enclosures; the spray pond and pumphouse, and the plant site perimeter. During these tours, observations were made relative to equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping, security, tagging of equipment, ongoing maintenance and surveillance and availability of redundant equipment. No unacceptable conditions were found.

3.3.1 Hourly Firewatch Discrepancy

The inspector discovered a fire watch inspection sheet for door 103 in the Reactor Enclosure on January 16, 1986, which had no sign-in entry between the hours of 4:36 a.m. and 6:12 a.m. on January 15, 1986. The door had been assigned an hourly firewatch patrol in accordance with Technical Specification 3.7.7. The door is a fire barrier separating the safeguards system access area and the residual heat removal equipment compartment on Reactor Enclosure elevation 201.

The inspector reviewed the firewatch log sheets for Door 103 for the 12-hour periods preceeding and following the time in question. All required inspections were documented. Bechtel construction assistants routinely tour firewatch areas every 48 minutes, inspecting for fire hazards and documenting each inspection on the log sheet by signature, date and time. An hourly inspection had been documented for the 12-hour periods prior to and after 5:00 a.m. on January 15, 1986. Firewatch personnel also retain a round sheet which is carried with them and on which a time is entered for each area inspected. The inspector reviewed the third shift (midnight to 8:00 a.m.) round sheet for the 19 fire areas requiring an hourly watch patrol on January 15, 1986. The round sheet contained an entry at 5:24 a.m. for Door 103. The inspector discussed this entry with the person responsible for the hourly firewatch (the Bechtel construction assistant), who stated that the inspection of Door 103 was made at 5:24 a.m. but that the inspection log sheet was inadvertently not signed. The log sheet is maintained locally at the firewatch area, and is required to be signed by Administrative Procedure A-12.1, (Revision 0). However, the round sheet is not procedurally required and is used by personnel performing firewatch inspections for logistic purposes.

The 19 areas patrolled on the third shift for January 15 were divided among four Bechtel construction assistants. Each person completed a patrol of the required 19 areas in approximately 28 minutes. Each area was inspected at 48 minute intervals on ten separate occasions during the shift. The inspector found all time entries on the log and round sheets for Door 103 to properly correlate, except for the 5:24 a.m. entry which was missing on the log sheet. The individual who performed the firewatch for Door Number 103 on January 16 was interviewed by the inspector, and stated that the inspection had been made but inadvertently not documented. The inspector, therefore, concluded that the inspection had been made as required by Technical Specifications but that the documentation required by Administrative Procedure A-12.1, Appendix C was inadvertently ommitted on one of the ten instances that Door 103 was inspected on the morning shift in question. Further, fire suppression systems in the area (Fire Zone 44) were operable at the time, and no combustibles were identified. The inspector considered the failure to document the inspection of Door 103 as an isolated case which has not been a recurrent problem.

However, the Bechtel firewatch shift advisor's log did not contain an entry which described this event, although the advisor had been aware of the event and was preparing a memorandum to the Regulatory Engineer addressing the missed signature. The inspector reviewed the memorandum and discussed this event with the Regulatory Engineer, noting that future instances should be documented in the shift advisor's log. The inspector had no further questions, and no violations were identified.

3.3.2 Control Structure Fire Door

The inspector found Door 543 at Control Structure elevation 304 open slightly at 10:25 a.m. on February 12, 1986. The inspector closed the door, informed shift supervision, and discussed this event with the Regulatory Engineer.

Door 543 is a large equipment access door, and is eventually intended to be electrically supervised via card reader when security program modifications are implemented. There is a smaller door (342) adjacent to Door 543 which is intended for personnel ingress and egress from this Control Structure area into the Turbine Enclosure ventilation fan room.

Door 543 is one of 110 fire doors which receive a position check once-a-shift in order to satisfy technical specification (once per day) requirements for unlocked, unsupervised fire doors. Surveillance test ST-7-022-370 had been performed for Door 543 on all three shifts on February 11 and 12, 1986. The inspector concluded that the door was slightly open for a period of time not greater than eight hours, and that the finding was an isolated instance which was not in violation of Technical Specifications. Fire suppression equipment was available in the area during the time, and an unrelated hourly firewatch was in effect in close proximity to Door 543. The licensee responded to the inspector's concerns by posting a sign on Door 543 indicating that it is an equipment hatch only, to be kept closed and latched, and that the adjacent smaller Door 342 should be used. The inspector had no further questions.

3.3.3 Security Member Leaving Post

The senior resident inspector was informed by the licensee on January 28, 1986, of an event discovered by the Station Manager whereby a security force member left his assigned post in the Turbine Enclosure for a brief period of time. The inspector subsequently verified that the licensee had taken appropriate compensatory measures, made an ENS notification to the NRC on January 29, and issued a Physical Security Event Report 86-01 on January 31, 1986. The inspector reviewed the applicable post orders and the event report, discussed the event with the Station Manager, and periodically observed proper adherence to the instructions for the post in question over the remaining inspection period. This event was the subject, in part, of an enforcement conference held at NRC Region I office on February 7, 1986.

3.4 Standby Liquid Control System Walkdown

The inspector independently verified the operability of the Standby Liquid Control System (SLC) by performing a walkdown of the accessible portions of the system and confirmation of the following items:

-- The system check-off list and operating procedures are consistent with the plant drawings and as-built configuration.

-- Valves and breakers are properly aligned, necessary instrumentation is functional, and appropriate valves are locked.

-- Control room switches, indications and controls in the proper position or configuration.

The following references were reviewed:

-- P&ID M-48

-- SLC Operating Procedure S48.1A

-- Equipment Alignment to place SLC in normal "Standby" conditions S48.1.A (COL)

No unacceptable conditions were identified.

3.5 QA/QC Interface with Operations

The inspector reviewed the Quality Assurance and Quality Control organization during the transition from startup test program surveillances to operational surveillances and audits. During 1985, Quality Assurance has performed a total of 16 surveillances and 50 audits of operations activities, and plans to perform at least one audit in each of approximately 68 identified operations areas within two years. The Quality Assurance organization has also developed a Quality Assurance Tracking and Trending System (QATTS) to help detect trends, track items and assess the effectiveness of the actions taken to correct trends previously identified as being adverse to quality. No unacceptable conditions were identified for this inspection, and a more detailed review will be performed in future inspections.

3.6 STA Training Programs

The inspector attended an STA training session devoted to transient analysis. The sessions were conducted in accordance with approved lesson plans, and was part of the 18th of 26 scheduled weeks of training. The inspector also reviewed the lesson plans, STA training program description, and discussed the above with the Limerick Training Coordinator. No unacceptable conditions were identified.

4.0 Event Followup

4.1 Manual Scram on January 13, 1986

A manual scram was initiated from 28% power on January 13, 1986, as part of a planned shutdown to troubleshoot the number 4 main turbine control valve (CV4). The valve failed to fully close during valve exercise testing on January 12, and remained in a 34% open condition. Reactor power was reduced to 70% on January 13 to attempt closing CV4. All systems operated properly following the manual scram. The mode switch was intentionally left in the RUN position until pressure dropped below 760 psig and a Group 1 MSIV isolation occurred. The MSIV isolation was intended to ensure that, if the corresponding main turbine stop valve for CV4 did not fully close, the turbine would be protected from an overspeed transient. The Group 1 isolation occurred within one minute following the scram. The maintenance activities associated with these valves are discussed in Detail 6.1.

The inspector reviewed temporary procedure change TPC-86-0049 to General Plant Procedure GP-3, Normal Plant Shutdown. The TPC directed that a manual scram be initiated with the mode switch left in RUN to receive the Group 1 MSIV isolation for turbine protection. The procedure was accurately followed by plant operators, and the inspector observed the scram. Post-trip conditions were as-expected: a main generator lockout was intentionally received to prevent main turbine overspeed; a manual 13 kV transfer was performed to maintain the reactor recirculation pumps in operation; an automatic turbine trip occurred; and, HPCI was started manually and placed in full-flow test configuration to control pressure with the MSIVs closed. The GP-18 Scram Review Procedure was completed, and the inspector verified that the Group I isolation occurred on main steam line low pressure (755 psig) with the mode switch in RUN. RCIC was also used for vessel makeup because of the MSIV isolation. No safety valves lifted and reactor conditions were maintained stable.

One problem identified involved the re-positioning of the reactor mode switch to Shutdown after conditions had stablized. When the operator attempted to position the switch out of Run, it would not move. The operator then found that the key was not in the switch and was locked in the Shift Superintendent's cabinet because supervision believed that the key could be removed in Run mode. The licensee attached an equipment tag to the mode switch directing operators to leave the key in except when the switch is locked in the Shutdown mode. Leaving the key in-place in the Run mode was found acceptable by the licensee's Nuclear Review Board. The inspector had no further questions, and no unacceptable conditions or violations were identified.

4.2 High Flux Scram on February 10, 1986

On February 10, 1986 the reactor scrammed from 99.8% power on a high APRM flux protection signal caused by an increase in reactor pressure. Reactor pressure increased to 1064 psig resulting in a high power flux scram at about 114%. An Unusual Event was declared at 2:45 p.m. and terminated at 3:00 p.m., with proper ENS notifications made. Plant conditions were stabilized, the cause of the scram was investigated and determined, and a plant startup begun. Criticality was achieved on February 11 and the plant was returned to full power by February 12.

The licensee determined the cause of the pressure/power increase to be a ground created in the turbine EHC control circuitry. The ground was momentarily present due to a voltmeter connected by a test engineer to the EHC system to gather turbine operating data. The ground caused the control valves to partially close thereby increasing pressure and causing power to increase.

The test engineer had been collecting turbine EHC test data during the startup test program beginning on October 15, 1985. The data were requested via a General Electric memorandum dated September 24, 1985 (Memo No. CRB-219). Four hours of steady state data were collected for the different parameters, one being EHC load reference voltage. The engineer was using a Digital Voltmeter Model 18050A or "Fluke", Serial No. 57-0084, for all cases. The meter had been calibrated on June 6, 1985, and was due for recalibration one year later.

The data collection at full rated load was postponed through the warranty run, and were taken on February 10, 1986. The test engineer used the data sheet attached to the September 24, 1985, GE memorandum, which specified the appropriate card locations and test points at which to connect the meter. The test engineer informed control room operators that he would be in the Auxiliary Equipment Room to collect the data. When he connected the meter to the card A29 location, test point 2 for EHC load reference voltage, a momentary ground was created and instead of the expected minus 5 volts, a zero reading was experienced. As a result, the EHC system caused all main turbine control valves to go shut.

The control valve closure caused reactor pressure to increase. Voids collapsed which increased neutron flux to the high power trip setpoint, and a scram occurred. All systems functioned properly following the scram, and no ECCS actuations or unplanned releases occurred. A 13 kV transfer to offsite power sources was manually performed, and therefore the recirculation pumps did not trip. An automatic turbine trip occurred. The inspector reviewed the sequence of events log and the GP-18 Scram Review Procedure for the event. All protective features functioned as designed, and the scram was reset approximately 40 minutes later. All rods inserted as expected, full-in indications were recorded, and the scram discharge volume isolated as required.

The inspector discussed this event with the test engineer taking the EHC readings, licensee management and operators, and I&C personnel who control issuance of digital volt meters. The volt meter in question was returned to the licensee's Engineering & Research Labs for evaluation of possible defects such as internal faults. The inspector questioned the adequacy of controls placed upon test equipment such as the digital voltmeter including the calibration frequency, service life and design appropriateness. The inspector questioned the lack of administrative controls applied to non-safety troubleshooting non-safety related equipment. The licensee has proposed expanding the scope of activities covered under Administrative Procedure A-41.1, Control of Troubleshooting, to include any test activity conducted in the Auxiliary Equipment Room with an approved procedure or administrative mechanism. The evaluation by the licensee of Digital Voltmeter 57-0084 and the use of these meters in general, the revisions to A-41.1 procedure, and other corrective actions to be included in a Upset Report, are considered collectively as an unresolved item. (86-03-01)

4.3 <u>Contamination of Unit 2 Turbine Enclosure Drain Sumps</u>

On January 15, 1986, while performing a routine quarterly sample of Unit 2 sumps, it was discovered that the Unit 2 Turbine Enclosure condensate backwash area equipment drain sump showed traces of Cobalt-58. Sampling found that the Unit 2 Turbine Enclosure condensate backwash area floor drain sump also showed traces of Cobalt-58.

The backwash area drain sumps are connected by an overflow. The contamination probably originated in one of these sumps, and was transferred to the other via the overflow. Prior to the discovery of the contamination, it was noticed that there was oil in the Unit 2 equipment drain sump from recent maintenance work on a Control Enclosure chiller. Water collecting in this sump is normally processed through radwaste, but rather than sending oil through radwaste, it was decided to sample and, if not contaminated, pump the oil to the Unit 1 oily waste sump. The oil was pumped into drums which were then mistakenly poured into the Unit 1 normal waste sump rather than the oily waste sump.

The Unit 2 equipment drain sump sample had a Co-58 concentration of 1.9(E-6) micro Ci/ml, while the Unit 1 normal waste sump showed 7(E-6) micro Ci/ml of Co-58 on January 15. Two days later, it was discovered that the normal and oily waste sumps were cross-connected at the bottom. The oily waste sump was then sampled and a concentration of 7(E-7) micro Ci/ml of Co-58 was found.

Holding Pond samples were then taken daily during January 16-21 and no contamination was found. A Holding Pond sludge sample on January 23 also showed no contamination. Culvert samples were taken as a precaution, and a stagnant water sample showed 3.1(E-7) micro Ci/ml of Co-58. The culvert was decontaminated on January 23.

The regulatory limit of (10 CFR Part 20) maximum permissible concentration for Co-58 is 1.0(E-4) micro Ci/ml, and the highest concentrations measured in this event were 7% of that value.

The inspector reviewed the licensee's Upset Report-019 approved on February 12, 1986, and discussed this event with personnel from chemistry and operations groups. No unacceptable conditions or violations were identified. The following long-term corrective actions were under licensee review:

- implement improved sampling techniques.
- label sumps to avoid confusion.
- develop a plan to control and monitor all water leaving the power block.

NRC followup of the results of these actions is considered an unresolved item. (86-03-02)

5.0 <u>Licensee Reports</u>

5.1 <u>In-Office Review of Licensee Event Reports</u>

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	Title
85-091*	Standby Liquid Control Outboard Isolation Valve
85-096	Failure to Perform a Technical Specification Surveillance Requirements (Toxic Gas Detection System)
85-097	Main Control Room Chlorine Isolation and Emergency Fresh Air System Actuation
85-098	Reactor Water Cleanup System Isolation
85-099	Unplanned Actuation of the Nuclear Steam Supply Shutoff System
85-100	Failure to Meet Hourly Fire Watch Requirement in Technical Specification
85-101*	Operating Without Toxic Gas Analyzis in Service for Approximately 27.5 hours
85-102*	Excessive Leakage of Containment Spray Valve, HV-51-1F016A
86-001*	Reactor Scrams on Reactor Low Water Level
86-002	Unplanned Isolation of the Reactor Enclosure
86-003	Unplanned Actuation of the Nuclear Steam Shutoff System
86-004	Unplanned Isolation of the Reactor Enclosure
86-005	Main Control Room Chlorine Isolation and Emergency Fresh Air System Actuation
86-006	Failure to Perform Technical Specification Surveillance Requirements

LER Number	Title
86-007	Main Control Room Chlorine Isolation and Emergency Fresh Air System Actuation
86-008	Main Control Room Chlorine Isolation and Emergency Fresh Air System Actuation
86-010	Noncompliance with License Condition 2.C.1 (Reactor Power Level)

5.2 Onsite Followup of Licensee Event Reports

For those LERs selected for onsite followup (denoted by asterisks in Section 5.1), the inspector verified 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 reviewed by the licensee, and that continued operation of the facility was conducted in accordance with Technical Specification limits.

5.2.1 LER 85-091; Standby Liquid Control Outboard Isolation Valve

The valve operator for the Standby Liquid Control System (SLCS) outboard containment isolation valve HV-48-1F006A was de-energized open for 21 hours on November 20-21, 1985, to allow preventive maintenance work on the valve operator. The valve is a motor operated check valve. The motor operator increases the seating force on the valve, even though the valve continues to function as an isolation valve (checking reverse flow) with the operator de-energized. The control room supervisor did not realize that de-energizing the valve open disabled, per the Technical Specifications, the containment isolation function of the valve. Therefore, Technical Specification 3.6.3, during reactor operation, would have required return to service within four hours or isolation of the penetration. The reactor was shut down with all control rods inserted during the period when the event occurred.

The inspector reviewed the vendor print drawing 8031-P-114A-204-4 for the valve and FSAR Section 6.2.4.3. The SLCS penetrates the drywell at two locations and these lines join inside the drywell to a single line to the reactor vessel core spray "B" loop. Two simple check valves are located on the line inside of the drywell (2-inch piping), and each of the lines outside of the drywell contain a motor-operated Rockwell-Edward globe stop check valve (valves 6A and 6B). The outboard 6A and 6B valves are provided with motor-operators to assist in closing the discs even though the check function of the valve would, by itself, stop reverse flow through the lines. Technical Specification Table 3.6.3, Note 29, applies to the outboard valves and states that they may be open during normal operation under procedural controls, but capable of manual isolation from the control room. Therefore, disabling open the motor operator technically renders the isolation valve inoperable, even though the check-function of the valve still exists.

The shift supervisor who authorized de-energizing open the motor operator for valve 6A did not recognize the effect on containment isolation, as defined in TS Table 3.6.3. The operator focused only the the operability of SLCS.

The licensee's corrective action was verified by the inspector. Stickers were affixed at the motor control centers of all containment isolation valves and hung on tags at all accessible valve motors which state:

> "Prior to manually operating or working on valve, ensure that Technical Specification requirements are considered by double-checking with the Control Supervisor."

The stickers and tags are intended to assure that operators are aware of containment isolation valve considerations.

The inspector discussed this event with operators and licensee supervision and management. The licensee agreed to add LER 85-091 and a discussion thereof to the operator requalification training program. The root cause of the operator's cognitive error was his focus on SLCS system operability, without providing equal attention to containment integrity.

The inspector had no further questions. Because the plant was shutdown, and the isolation check functions of valve 6A and 6B as well as the two inboard check valves were available, the inspector did not judge this event to be a safety problem. Since the licensee discovered the violation during a control panel walkdown, and reported it via LER 85-091 with appropriate corrective action that had not been associated with a previous similar occurrence, the inspector considered this event to be a licensee identified item. Therefore, under the provisions of 10 CFR Part 2, Appendix C regarding self-identification and correction of problems, a Notice of Violation was not issued.

5.2.2 LER 85-101; Operating Without Toxic Gas Analyzers in Service for Approximately 27.5 Hours

On December 28, 1985, because of a lifted relief valve on the Nitrogen Inerting System, the primary nitrogen supply line to the toxic gas analyzer was isolated. The purpose of the nitrogen supply is to provide a reference for zero adjustment of the toxic gas analyzer on an hourly basis. When the nitrogen supply line is isolated, the toxic gas analyzers automatically draw from a backup nitrogen bottle system. The surveillance of the backup nitrogen bottle system is performed on a daily basis and, once the bottles read below 200 psi, the bottle is replaced. On December 30, 1985, the toxic gas analyzer system was declared inoperable due to the backup nitrogen supply bottles being empty and disconnected in preparation for being replaced. The control room ventilation was placed in the chlorine isolation mode. The nitrogen bottles were replaced and the analyzers returned to service.

The licensee, in reviewing the consequences of the event, determined their effects to be of minimal significance based on the following. First, even though the nitrogen bottles were disconnected, the analyzers were being zeroed with air and could have functioned appropriately in the event of a sudden toxic gas occurrence. Secondly, the likelihood of a toxic gas occurrence outside the plant, along with the simultaneous occurrence of unfavorable meteorological conditions, is relatively small.

The licensee has taken the following actions to prevent recurrence. A "CAUTION" note will be placed in the nitrogen supply system operating procedure S57.8A to remind the operators that isolation of the nitrogen header also affects the toxic gas analyzer system. Instructions will be placed in the toxic gas analyzer system operating procedure S78.1F addressing operation of the nitrogen zero gas supply, including instructions for replacement of the backup nitrogen supply bottles. An information tag has been placed on the nitrogen bottles indicating that removal of the bottles from service may cause the inoperability of the toxic gas analyzer. Finally, the daily log description for the toxic gas analyzer, nitrogen gas backup bottles, has been changed to eliminate ambiguity and to aid in better operator understanding of this bottle pressure reading entries.

The inspector noted the lack of non-licensed operator familiarity with the backup nitrogen bottle system. When non-licensed operators take bottle pressure readings, bottle pressure is recorded but not outlet pressure, which is an equally important parameter. In response to the inspector's comments the licensee removed the backup nitrogen bottle readings from the auxiliary operator's round sheets, and added the reading of the bottle pressures (and also the outlet pressure) to the daily surveillance sheet ST-6-107-590-1. This item will be reviewed in a future inspection (50-352/86-03-03).

5.2.3 LER 85-102; Excessive Leakage of Containment Spray Valve, HV-51-1F016A

On December 18, 1985, a local leak rate test (LLRT) was performed on penetration 39A, for the drywell spray header. During the performance of this test, both the inboard and outboard valves were stroked normally then pressurized to the test pressure of 44 psig. The penetrations failed to hold pressure until the outboard isolation valve (HV-51-1F016A) was tightened manually.

The penetration then successfully passed the LLRT. At that time, the licensee ordered a MOVAT's to be performed on valve HV-51-1F016A. The test revealed that excessive grease in the torque sensing mechanism of the Limitorque operator is possibly causing improper operation of the valve due to high internal valve friction.

The inspector reviewed the licensee's corrective actions which involved applying a supervisory block to the hand switch in the control room, the motor control center and the manual handwheel for HV-51-1F016A valve to secure it in the full closed position and de-energized during plant operation. The licensee also plans to cut a slot in the torque limit sleeve of the spring pack which will allow the release of any excess grease. An LLRT will then be performed to verify an acceptable leak rate. The inspector had no further questions at this time.

5.2.4 LER 86-001; Wide/Narrow Range Water Level Indicator Discrepancies

The plant was shut down on January 2, 1986 as part of startup test STP-27.4, the full power turbine trip. The reactor had been in the Hot Shutdown mode for approximately two hours, with all rods inserted, when two low reactor water level scram signals were received within 90 minutes of each other. The scrams resulted from a discrepancy between the wide range and narrow range reactor water level indications.

During recovery from the planned turbine trip test, the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems were being used to control reactor pressure and level. A panel operator was controlling level with RCIC based on wide range level instrumentation, however, reactor protection system logic uses the narrow range level instrumentation. As the reactor pressure and temperature decreased, the density of water in the reference legs of the instruments increased. The wide range instrument reference leg water column is longer than the narrow range column, and together with the density change caused a discrepancy between the wide and narrow range level indications. When the wide range instrumentation indicated level to be 20 inches, the narrow range instrumentation indicated a value of 12.5 inches, which is the RPs narrow range trip setpoint causing the RPS to generate a scram signal.

The inspector discussed this event with the Operations Engineer and several licensed operators. Wide and narrow range instruments are calibrated for saturated water at 1000 psig, conditions. The discrepancy, due to reference leg differences and increased density at low temperature and pressure, becomes greater as pressure is further decreased. The inspector verified that the licensee had placed an operator aid, Operations Control Number 42-16, on the console in front of HPCI/RCIC control panel 601. The aid is a graph of wide versus narrow range indicated level differences as a function of reactor pressure, and serves to remind the operators of the density effect at lower pressures on those instruments. The licensee is also evaluating a design change to bypass the low level scram under these conditions. No unacceptable conditions were noted. The inspector had no further questions.

5.3 Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee were reviewed by the insepctor. The reports were reviewed to determine that the report included the required information, that test results and/or supporting information were consistent with design prediction and performance specifications, that planned corrective action was adequate for resolution of identified problems, and whether any information in the report should be classified as an abnormal occurrence.

The following periodic and special reports were reviewed:

-- Monthly Operating Reports; December, 1985 and January, 1986

-- 1986 Emergency Preparedness Exercise Description

-- Special Report RCIC Actuation and Injections, dated December 18, 1985

-- Special Report - RCIC Actuation and Injections, dated November 5, 1985

These reports were found acceptable.

6.0 Maintenance and Surveillance Observations

6.1 Maintenance on Main Turbine Control Valves and Stop Valves

During this period, work was observed under Maintenance Request Forms (MRF) 86-00378, 86-00444, 86-00445, 86-00446, 86-00423, which involved repairs to Control Valve number 4 (CV4), and inspection of all four stop valves. On January 12, 1986, while performing ST-6-001-765-1 Main Turbine Control Valve Exercise and Channel function check, CV4 closed to 33%. Based on the performance of the surveillance test, an MRF was written to investigate the problem. After CV4 was disassembled, it was discovered that a bolt from the disc cap of the upstream stop valve was lodged between the seating surfaces. Also found were indentations in the plug and body of the seat surfaces, and raised metal in the same areas. The inspector witnessed the resurfacing of the high spots of the damaged areas of the plug and seat, and also viewed the dye check of the seating areas, which were satisfactory. The licensee then disassembled the number 4 stop valve (SV4), replaced the missing bolt and torqued to the required 550 ft/lbs. The other seven SV4 bolts were checked for proper torque and staked. As a precautionary measure, the remaining three stop valves were disassembled and checked, and the disc-cap bolts were checked for proper torque and restaked.

No violations were identified.

6.2 Surveillance Activities

The inspector observed or reviewed the performance of selected surveillance tests to determine that: the test procedure conformed to technical specification requirements; administrative approvals were obtained before initiating the test; testing was accomplished by qualified personnel in accordance with an approved procedure;

test instrumentation was calibrated; limiting conditions for operation were met; test data was accurate and complete; removal and restoration of the affected components were properly accomplished; test results met Technical Specification and procedural requirements; deficiencies noted were reviewed and appropriately resolved; and, the surveillance was completed at the required frequency.

6.2.1 Daily Jet Pump and APRM Flow Unit Operability Verification

The inspector reviewed the results of ST-6-043-320-1 conducted on January 30, 1986 involving a daily operability check of the jet pumps and the APRM flow unit verification. The purpose of this surveillance test is to verify that each of the jet pumps and APRM flow units operate within technical specification limits. The indicated total core flow, based on the recirculation pump speed and flow, was within technical specification limits and did not differ by more than 10% from the established total core flow as indicated from the APRM flow units. The inspector noted one problem concerning recording the data in the attached figures of the surveillance test procedure in that certain recorded information was plotted incorrectly. This problem was pointed out to the licensee who immediately instructed the operators to take proper precautions in recording the data. The inspector had no further questions, and no violations were identified.

6.2.2 Standby Liquid Control System Flow Test

The inspector observed portions of the quarterly pump and valve test ST-3-048-230-1 for the Standby Liquid Control System (SLCS). Test results were found to meet acceptance criteria and Technical Specification requirements, and the inspector verified that the licensee's independent verification of restoration (IVOR) of system components was correct.

The inspector found that Table II of the test procedure was very useful in making the required locked valve entries in the Locked Valve Log in main control room. The format of Table II matches the Locked Valve Log, and the IVOR required for the affected valves was properly performed. However, the inspector noted that the IVOR used for other valves positioned during the test was not performed independently since the operator performing the SLCS valve manipulations was the same individual who initiated the IVOR data sheet. The improvement of IVOR methods is being followed as part of NRC unresolved item 85-43-03.

The inspector also noted an outstanding equipment trouble tag (ETT)-7059 which had identified SLCS heat tracing alarms at local panel 10C232 on April 20, 1985. As of the date of this inspection, there were eight alarms indicating heat tracing problems but the ETT was still unaddressed. No abnormal SLCS tank or line temperatures were observed by the inspector. The licensee agreed to initiate maintenance action to repair the trouble alarms.

The inspector questioned the calibration frequency for local pressure indicator PI-48-IR0C3 used during the test. The instrument sticker showed the last calibration as being November 7, 1983. The calibration frequency was not known when the test engineer performing ST-3-048-230-1 was questioned; however, the inspector subsequently verified that the period was specified as three years. The licensee agreed to incorporate reference of calibration frequency of PI-48-IR003 into the test procedure. Also, a portable flow meter used for the test could not be verified as in-calibration. The meter is a Controlatron Model 244-23 and is provided by the licensee's West Conshohocken Gas Plant lab. The licensee subsequently verified that the meter was in calibration, and agreed to initiate a sticker program for these types of meters so that proper calibrations can be determined at the time and location of the test.

Finally, the inspector independently determined that post-test conditions of SLCS were within Technical Specification limits with tank temperature at 83 degrees F and level at 4700 gallons, and that the pump discharge explosive squib valves were rearmed (fuses re-installed) and control room continuity lights were lighted.

The inspector had no futher questions, and identified no violations.

6.2.3 Containment Purge and Exhaust Valve Log

The inspector reviewed the purge and exhaust valve log used to track the time that containment purge or exhaust lines are open and in use during plant operation. Technical Specification 3.6.1.8 limits the time that purge or exhaust lines are open to 90 hours in any consecutive 365 day period when the reactor is not in Cold Shutdown. The inspector verified that the correct valve combinations were being considered, and that the licensee had accumulated approximately three hours of open operation in the past year.

The inspector also reviewed Operations Engineer Control Aid 57-31 which required use of a primary containment inventory makeup log as of January 28, 1986. The log is intended to track possible containment leakage and resultant nitrogen makeup requirements using the smaller 2-inch HV-57-116 valve. Drywell and suppression pool pressure are required by Technical Specifications to be maintained positive and between 0 to 2.0 psig. Entries between January 29 and February 6, 1986 were reviewed, indicating that approximately once per day for 1 to 2 hours, nitrogen was supplied at 25-125 scfm to maintain required pressures. Drywell and suppression pool pressures were periodically observed to be within required limits throughout the inspection period. No unacceptable conditions were noted.

6.2.4 Thermal Limits Determination

The inspector reviewed the results of ST-6-107-885-1 which is performed daily to verify core thermal limits are being maintained less than 1.0. The surveillance for January 29, 1986, was compared against the process computer P-1 printout used. Calculated reactor power was 3272 MWt or 99.4%, with the following core thermal limits:

Critical Power Ratio (CMFCP)	0.836
Limiting Power Density (CMFLPD)	0.901
Average Planar Linear Ratio (CMAPR)	0.899

As discussed in Detail 7.6.3, the feedwater flow transmitter calibration problem found and evaluated on January 29 amounted to an underestimate of approximately 0.6% or 21 MW in calculated core thermal power. Therefore, the maximum effect of this discrepancy on the above thermal limits represents an approximate 10% margin to the upper limit of 1.0. With the assumed 0.6% or 21 MW error taken into account, actual core power for P-1 data described above is 3293 or exactly 100% rated thermal power.

The inspector verified APRM readings recorded for ST-6-107-885 were accurate, and that the high power trip setting was 119.3% and the rod block was 110.3%. The ratio of fraction of rated power to CMFLPD was verified to be greater than 1.0 (i.e., no readjustment of APRM gains required), and the independent verification for the surveillance test satisfactorily documented that all operable APRMs were not bypassed.

No unacceptable conditions were noted.

7.0 Startup Testing

The licensee completed the final phase of TC-6 testing during this inspection period, and the warranty run was completed during the period January 23-28, 1986. The test program was ending with the declaration of commercial operation on February 1, 1986.

7.1 Major TC-6 Test Evolutions

The following startup tests were witnessed, in part or fully, and test results were reviewed. Level I criteria were evaluated, discussed with test personnel and licensee management and found to be met. The tests are further addressed in NRC Inspection Report 50-352/86-05.

STP-30.1, Single Recirculation Pump Trip
STP-23.7, Maximum Feedwater Runout Capability
STP-23.5, Feedwater Pump Trip
STP-1.4, Reactor Water Cleanup Test
STP-34.1, Offgas Performance Verification

No unacceptable conditions were identified, test criteria were properly met and evaluated and approved by the PORC.

7.2 Warranty Run Testing

7.2.1 STP-20.1, Two Hour Demonstration

During the continuous warranty run, data were taken for three 2-hour periods, and a manual heat balance calculation was performed to determine core thermal power. The heat balance calculation is performed in conjunction with process computer program OD-3, and at the same time (beginning, middle and end points) as the 100 hour STP-20.2 test. The test used differential pressure meters connected at the spare taps for the feedwater flow meter test connections. These meters were independently calibrated and in a different range of interest than the permanent feedwater flow transmitters.

The inspector observed testing and data collection from January 23 through 28, 1986. Core thermal power values were 3300, 3319 and 3288 for an average of 3302 MWt. The average was 9 MW greater than full rated but later determined via Test Exception No. 411 to be within the accuracy of the analysis. Another Level 1 test criterion violation which was satisfactorily dispositioned by Test Exception No. 382 regarding steam supply at rated flow and 1020 psia reactor steam dome pressure, instead of at 985 psia discharge pressure at the second MSIV, because of the location of the test tap too close to the valve to permit appropriate flow conditions.

The inspector reviewed a GE memorandum dated January 31, 1986, which provided the following justification that the test data were within instrument accuracies and design bases:

-- Plant and core conditions were monitored by the process computer and all indicated parameters were within rated conditions. It was reported, however, that all hot bundle thermal margins were better than required limits (by about 10%) even when the miscalibration factor is considered.

-- All transient safety evaluations in the FSAR are conservatively done (e.g., with Tech Spec limits and at end-of-cycle conditions), and were also done at 104.3% of 3293 MWt power conditions. Therefore, adequate transient protection was always present.

-- Loss of Coolant Accident analysis in the FSAR was con ducted assuming 102% of 3293 MWt power conditions. This includes 102% hot bundle conditions as well as total power. Therefore, the LOCA/ECCS evaluations bounded the operation.

-- The GETAB MCPR Safety Limit has been chosen with clear recognition of the presence of uncertainties in plant measurements. About 2% is allowed for thermal power measurement uncertainty in that statistical basis. The observed operation was well within this allowance.

No unacceptable conditions were noted, and the inspector had no questions regarding STP-20.1.

7.2.2 STP-20.2, 100-Hour Demonstration

The reactor was run at or near rated power for a 100-hour period, and average core thermal power was determined from hourly OD-3 calculations by the process computer. Near steady-state reactor conditions (i.e., no control rod position or core flow adjustments more frequently than every 4 hours) were maintained throughout this test to hold reactor power constant within ±2% as read from plant instruments. The inspector observed portions of the conduct of this test during the period January 23-28, 1986.

Average core thermal power was determined to be 3266.83 MWt or 99.2%, and conditions were within core thermal limits. However, Test Exception Report No. 417 documented a discrepancy in core thermal power of approximately 25 MWt, when STP-20.1 hand calculations were compared with OD-3 printout from the STP-20.2 subtest. Therefore, after evaluation of this data discrepancy on January 28-29, 1986, the licensee concluded that the process computer (which was using permanently installed feed flow instruments for input) was underestimating core thermal power by approximately 1% because of a miscalibration of the permanent feedwater flow transmitters.

The Station Manager imposed an administrative limit on reactor power to 3253 MWt at 6:00 p.m. on January 29. Recalibration of the three permanent feed flow transmitters was performed on January 30-31. The licensee made an ENS call to the NRC at 7:02 p.m. on January 31, 1986, and LER Number 86-010 was later issued on March 3, 1986, describing the power calculation discrepancy. Recalibration of the permanent feed flow transmitters was accomplished by 5:30 a.m. on January 31. General Electric assessed the effects of the discrepancy on startup test program results in a February 13, 1986 memorandum (GE-SM-258), and found it to be insignificant and well within the accuracy and acceptance criteria of the tests. The observed calculated power discrepancy was an example where the test program identified and corrected a problem which may not otherwise have been detected.

7.2.3 Feedwater Flow Transmitter Miscalibration

The licensee's review of warranty run test data led to the discovery of an error in the calibration of the feedwater flow transmitters which amounted to an underestimate of calculated (by process computer heat balance) core thermal power on the order of 25 MW. The flow transmitters supply feed flow input to the process computer and the feedwater control system.

During a period of 18 days between December 26, 1985 and January 29, 1986, the reactor had been operated for the first time at conditions close (98-100%) to full rated power. Full power was initially reached on December 26. The plant was shutdown on January 3-10 for turbine intermediate valve and cross-over piping repairs; and again on January 14-20 for control valve repairs. Because of the 0.6% power underestimate discovered on January 29, the possibility existed that when re-examined, reactor operation had at times exceeded the 100% or 3293 MWt licensed limit.

The licensee reviewed process computer output for the period in question and identified a total of 138 hours of plant operation during the period in question when the reactor was operated in excess of the 3293 MWt limit. The time was based on the assumption that the error amouted to a difference of 21 MW which was, in turn, observed from process computer calculations at similar plant conditions (core flow and electrical output) just prior to and after the transmitter recalibrations.

Process Computer Calculations

Parameter		
Date/time	1/30, 11:29 pm	1/31, 5:41 am
Core thermal power (MWt)	3259	3280
Electrical output (MWe)	1097.3	1096.4
Core flow (%)	98.4%	98.4
Thermal limits: (see Detail 6.2.4)		
CMFCP	0.833	0.837
CMFLPD	0.897	0.901
CMAPR	0.896	0.901
Total Feedwater Flow (million pounds per hour)	14.14	14.24

The process computer thermal limit calculations shown above demonstrate that the increase in critical power ratio (CMFCP), limiting power density (CMFLPD) and average planar linear ratios (CMAPR) due to the transmitter recalibration were bounded and were still well within the technical specification limit of 1.0 placed on these parameters. The margin of approximately 10% was maintained because of the core management scheme presently being followed by the licensee with control rod patterns to minimize significant "bottom burning" of fuel. Therefore, at no time during the period when licensed thermal power was exceeded did core thermal limits approach the 1.0 limit. The inspector reviewed the highest power reading found during that period (December 31, 1985 at 8:54 pm) of 3305 MWt. With the 21 MW error, power at that instant was actually 3326 or 101%. Corresponding thermal limits (prior to and after correction for the error) were still within Technical Specifications as follows:

Thermal Limit	Initially Calculated (P1)	Corrected
CMFCP	0.840	0.844
CMFLPD	0.931	0.935
CMAPR	0.934	0.939

The corrected values were scaled-up using the calculated ratios for January 30-31 addressed above.

The inspector discussed the origin of the calibration error with licensee representatives, and reviewed the original calibration data sheets. The original data sheet was inaccurate, and calculated that a flow range of 0 to 5.5 million lbs/hr corresponded to a differential pressure of 0 to 756 inches of water. A change directed that the transmitter's range be extended to cover flow from 0 to 7.0 million lbs/hr, and this change was made by scaling up from the incorrect 5.5 million lbs/756 inches of water reference point. Thus the flow transmitters were calibrated such that 7.0 million lbs/hr was equivalent to 1225 inches of water instead of the correct value of 1206 inches water.

The inspector reviewed the instrument recalibrations performed on January 30, 1986, for the three transmitters FT-006-IN003A, B and C. The flow elements are calibrated venturi sections with laboratory-verified correlations between flow and pressure drop. Permutit Drawing No. 556-28036 specifies a predicted differential pressure of 50.07 feet of water (600.84 inches) at 4.941 million lbs/hr of feedwater flow. This value, when scaled to a full range of 7.0 million lbs/hr, correctly provides the 1206 inch value currently used. The most recent recalibrations were performed for a full range shifted from 1225 to 1206 inches of water, and the recalibrations were within the required ± 0.25% accuracy specified. The licensee intends to recalibrate the feedwater flow transmitters on a more frequent basis, although the instruments are not safety related.

The inspector concluded that this event represented a licensee-identified item as described in 10 CFR 50 Appendix C. No violation was issued since the licensee discovered the error and promptly and conservatively corrected the transmitted calibration. No thermal limits were violated, the reactor was shown to remain within analyzed transient conditions, and the event existed over a relatively short period of time. Finally, the licensee accurately reported this event in LER 86-010, and had experienced no similar problems for which previous corrective action should have prevented the error. No violations were identified.

8.0 Unresolved Items

Unresolved items are items about which more information is required to ascertain whether they are acceptable or constitute a deviation or a violation. Unresolved items are discussed in Details 4.2, 4.3 and 5.2.2.

9. Exit Meeting

The NRC resident inspector discussed the issues and findings in this report throughout the inspection period, and at exit meetings held with Mr. G. Leitch and others of your staff on February 19 and 28, 1986. At this meeting, the licensee's representatives indicated that the items discussed in this report did not involve proprietary information. No written material was provided to the licensee during this period.

Licensee/Facility	Notification/Subject
Limerick Unit 1 DN 50-352	3/12; SRI PC RWCU Isolation

Description

The reactor water cleanup (RWCU) inboard isolation valve closed at 1:39 a.m. on 3/12. The isolation was caused by a defective differential temperature switch associated with the steam leak detection system for the "B" non-regenerative heat exchanger room. The spurious isolation occurred during a daily surveillance where the operator reads indicated temperature using a Riley temperature module. A similar isolation of RWCU occurred on 2/23/86 and had been a frequently experienced problem in early 1985. The RWCU isolation was reset, reactor water chemistry was unaffected, and the licensee made an ENS call at 5:20 a.m. The resident inspectors are following the licensee's evaluation of RWCU Riley temperature switches.