U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No.	89-21 89-30
Docket No.	50-352 50-353
License No.	NPF-39 NPF-85
Licensee:	Philadelphia Electric Company Correspondence Control Desk P.O. Box 7520 Philadelphia, Pa 19101
Facility Name:	Limerick Generating Station, Unit 1 and 2
Inspection Period:	October 11 - November 20, 1989
Inspectors:	T. J. Kenny, Senior Resident Inspector L. L. Scholl, Resident Inspector M. G. Evans, Resident Inspector

Approved by: Lawrence T. Doerflein 1/24/90

Lawrence T. Doerflein, Chief, Projects Section 2B — Date

Summary: Routine daytime (273 hours) and backshift/holiday (34 hours) inspections by the resident inspectors consisting of (a) plant tours, (b) observations of maintenance and surveillance testing, (c) review of LERs and periodic reports, (d) review of operational events, (e) system walkdowns, and (f) observation and results review of power ascension activities on Unit 2.

Results:

Operator performance during the Unit 2 startup testing and the plant trip was excellent and very professional.

The startup test program continued to progress satisfactorily and was well managed.

PECo reported all reportable conditions on time and in the proper manner. A noteworthy event was the Unit 2 trip from 98% power due to improper settings of the main transformer protective relays. (Section 2.2)

Two Engineered Safety Feature System Walkdowns were conducted with no negative findings. (Section 2.2.2)

Station personnel reassignments are documented in Section 8.0.

The licensee's corrective actions concerning a personnel heat stress incident were thorough (Section 9.0).

DETAILS

1.0 Persons Contacted

Within this report period, interviews and discussions were conducted with members of PECo management and staff as necessary to support inspection activity.

2.0 Operational Safety Verification

The inspectors conducted routine entries into the protected areas of the plant, including the control room, reactor enclosure, fuel floor, and drywell (when access is possible). During the inspection, discussions were held with operators, health physics (HP) and Instrument and Control (I&C) technicians, mechanics, security personnel, supervisors and plant management. The inspections were conducted in accordance with NRC Inspection Procedure 71707 and affirmed PECo's commitments and compliance with 10 CFR, Technical Specifications, License Conditions and Administrative Procedures.

2.1 Inspector Comments and Findings (71707, 93702)

Unit 1 began the period at 100% power and Unit 2 was at approximately 15% and increasing power to establish conditions for Test Condition 3.

On October 13, the Unit 2 high pressure coolant injection (HPCI) system was declared inoperable due to a clogged drain on the turbine exhaust drain pot. The line was cleared and the system returned to service the same day. The NRC was notified via the ENS since HPCI is a single train safety system.

On October 22, at 8:30 p.m., the control room channel "A" toxic gas analyzer alarmed due to a high vinyl chloride signal. The operators initiated a control room isolation and donned self contained breathing apparatus in accordance with established plant procedures. Backup air samples were then taken and no detectable amounts of vinyl chloride were found. Followup investigation by the licensee determined that a short duration release of vinyl chloride had occurred at a nearby chemical plant.

On October 25, the Unit 1 "A" Reactor Protection System Static Inverter circuit breaker tripped during a transfer of the inverter from its alternate to its normal supply. The inverter had been aligned to the alternate supply to perform maintenance. The breaker trip resulted in several system isolations due to the loss of control power. The breaker was closed and the isolations reset without any effect on plant operation. When initial troubleshooting did not reveal any reason for the breaker trip, the breaker was replaced and returned to the vendor for further investigation.

On October 25, two Unit 1 reactor water cleanup (RWCU) system isolations also occurred. These were due to a leaky relief valve which caused the room temperature to increase to the sensor setpoint and to a steam flooding damper which inadvertently closed due to condensation buildup in its differential pressure instrument line. The instrument line was drained to permit resetting of the damper and the relief valve was repaired.

On October 27, a fuse blew in a Unit 2 outboard isolation valve circuit and resulted in the closure of several drywell chilled water, reactor enclosure cooling water and containment instrument gas system valves. The fuse was replaced and the isolations reset in accordance with plant procedures. No immediate cause for the blown fuse was apparent. Any additional information will be reviewed in a future report as part of the licensee event report review.

On November 2, at approximately 9:02 a.m., the Unit 1 "A" reactor feed pump was inadvertently tripped when a maintenance mechanic bumped a conduit which was in contact with the pump's vibration transducer. The loss of the "A" loop feed flow resulted in decreasing reactor vessel level and per design a recirculation pump runback occurred when vessel level decreased to approximately 28 inches. The automatic runback reduced power to 75% and level was restored to normal within four minutes. The minimum level reached was 28 inches and the maximum was approximately 42 inches. All systems operated as designed. The conduit was relocated away from the vibration transducer and the feed pump was restarted. Power was then further reduced manually to 50% of rated to accomplish a rod sequence exchange which was scheduled for November 5. Following the rod pattern adjustments power was restored to 100%.

On November 3, Unit 1 power was reduced to 50% to perform scram time testing on 26 control rods and to repair a weld leak on the turbine control valve electro-hydraulic control system piping. Following the testing and repairs, power was returned to 100%.

On November 10, at 7:00 a.m., the Unit 2 reactor water cleanup system (RWCU) regenerative heat exchanger relief valve lifted, and failed to reseat. The resulting steam caused an actuation of the steam leak detection system causing an isolation of the RWCU system. While operations personnel were restoring the system, an additional expected isolation occurred due to a high differential flow signal because of the prior depressurization of the system downstream of the regenerative heat exchanger. The relief valve was subsequently repaired and the system returned to operation. Due to recurring problems on both Units 1 and 2, PECo plans to replace the existing relief valves with those manufactured by a different vendor.

On November 10, Unit 2 scrammed from 98% power. Plant restart occurred on November 14. See Section 2.2 for details.

On November 19, the Unit 1 reactor water cleanup (RWCU) system isolated due to a defective switch when a plant operator was taking daily surveillance readings on (TTS-44-1N600M) "1B" non-regenerative heat exchanger room area temperature. The leak detection system functioned to isolate the RWCU outboard isolation valve (HV-44-1F004) which isolated the RWCU system and caused the RWCU pumps to trip on low flow. All equipment isolated as required and functioned properly.

On November 20, an ESF actuation occurred due to refuel floor low differential pressure caused by a storm with a 15 degree Fahrenheit (F) temperature decrease and high gusting winds. When the low differential pressure setpoint was reached the containment ventilation system isolated and the standby gas treatment system started. All systems performed properly and the isolation was reset after the storm.

At the completion of the inspection period Unit 1 was at 100% power and Unit 2 was in Test Condition 6 at approximately 95% power.

2.2 Unit 2 Reactor Scram

On November 10, 1989 at 2:22 p.m., Unit 2 scrammed from 98% power due to a turbine control valve fast closure. The turbine valves closed as a result of a signal from "A" phase differential relay on the main transformer. During the event the High Pressure Coolant Injection (HPCI) system turbine started and tripped on overspeed six times. The reactor operator noticed this and secured the turbine because the reactor level was at 0 inches and HPCI is not required until level drops to -38 inches. The Reactor Core Isolation Cooling (RCIC) system also received a spurious partial initiation signal; however, the signals did not exist long enough for a full system initiation.

The inspector reviewed the results of PECo's investigation of this event and noted the following:

1. All three differential current relays on the output transformers were set too low because of a calculation error made when determining the setpoints. Unit 1 output transformers are 230kv and Unit 2's are 500kv, therefore new calculations for the relays were necessary. During the calculations the factor for three phase circuits (square root of three) was omitted from the calculation resulting in a setting that was too low for 100% output.

   PECo has corrected the calculations, recalibrated the differential current relays and tested them satisfactorily. All other relays installed on 500kv circuits as well as the Unit 1 protective relays have been checked for similar improper settings and none were found. This corrected the cause of the turbine trip.

2. As noted above, HPCI started on a reactor vessel low water level signal even though actual water level was well above the initiation setpoint. This was due to "spiking" on some of the water level signals.

   An evaluation was prepared in response to concerns for the performance of reactor water level instrumentation during the plant transient. The purpose was to evaluate the impact on plant operations and plant safety posed by oscillations (ringing or spiking) of some water level signals and the subsequent affect on the various systems that receive these signals.

   During the event actual reactor level dropped to about zero inches within 6 seconds after the scram. During the initial one second period following the start of the transient, level oscillations were recorded by the plant monitoring system (PMS) computer from transmitters on 2 of the 4 instrument reference legs and resulted in momentary HPCI and RCIC initiation signals.

   The PMS computer monitors 9 out of 34 level transmitter signals on 3 out of the 4 instrument reference legs. Of these monitored signals, two are normally over-ranged (fuel zone) and provide no information during transient testing. Extensive monitoring and numerous special tests have been performed which correlates the PMS level points and the remaining unmonitored level signals. All transmitters on the same instrument reference leg have been demonstrated to behave in a similar manner. Therefore the PMS points are considered representative of the "typical output" for those transmitters which are on the same reference leg as the monitored instrument.

It was previously noted that the transient oscillations on water level signals appear to be more extreme on the A and the B instrument reference legs, with the "B" leg being worse than the "A" leg. During the last mini-outage, lanyard pots were installed on these instrument lines near the condensing chambers to monitor vibration during plant transients. A review of the data obtained from a recent high power scram indicated that the transient oscillation of water level signals is not related to line vibration. Previous testing also indicated that flex hoses to the instruments, although they may aggravate the situation, are also not the source. The licensee's investigation as to the cause of the instrument level spikes is still ongoing. Further data will be taken during the next two planned transients and analyzed for possible improvements.

During this event, reference leg "A" and "B" both had down scale spikes. The response was similar to previous plant performance during transient testing. The duration of the down spike below the level 2 (-38 inches) trip unit setpoint was about 60 milliseconds, which may be of sufficient length to seal-in some but not all relay logic depending on relay types installed.

Only the "B" reference leg water level instruments received an up scale spike. A review of the plant's response to previous transients (i.e. MSIV isolation, scram and turbine trip from low power), showed that only transmitters on the "B" reference leg received an up scale spike. During this transient, the spike was of sufficient magnitude to exceed level 8 trip unit set points. The duration of the up scale spike was about 70 to 90 milliseconds which again is sufficiently long to seal-in some but not all relay logic (depends on relay type installed).

A turbine trip from high power is the most severe transient that the plant is anticipated to undergo from an instrumentation response viewpoint. The full MSIV isolation will produce significantly smaller spikes, and is not expected to approach a level 8 trip point.

The licensee determined the Unit 2 water level instrumentation system performance during this transient was significantly better than the Unit 1 system performance for the same transient. Unit 1 had spikes of much larger amplitude, duration, and repetition.

In summary, the reactor water level signal oscillations experienced during this trip were expected based on previous testing on both Unit 1 and 2. Actual water level indications were available to the operators throughout the transient and as such upon initiation of HPCI and/or RCIC these systems could be secured based on correct, redundant level indications.

3. As noted above, although HPCI initiated, RCIC only received a spurious partial initiation signal but did not start. During inspection after the scram, the only items which indicated RCIC activity or response was the white seal-in light was illuminated and the "RCIC initiate" computer point had been received. No other equipment response (valves and pump) had occurred. Also, actual reactor level never dropped below 0 ± 1 inch during the scram.

   The RCIC initiation logic consists of a 1 out of 2 twice logic of relays energized by low water level (-38 inches). RCIC signals are received from Division 1 and Division 3 while HPCI signals are received from Division 2 and Division 4. As noted above, the duration of the water level signal spikes was a factor in determining if a particular relay logic seals in. With respect to RCIC, the momentary initiation spike appears to have only been long enough to seal-in the white light and PMS indication. Since the signal was not long enough to energize other relays, the lack of equipment response could be expected.

   Surveillance testing ST-2-042-665-2, "ECCS, RCIC and NSSS - Reactor level and pressure, and Drywell pressure, Division 1 and channels A and J functional test," (partial), ST-2-042-631-2, "RCIC - Reactor vessel water level - Levels 2 and 8, Division 1, channel E functional test;" and ST-2-042-669-2, "ECCS and NSSS - Reactor level and pressure, Drywell pressure, Division 1, channels E and N functional test," (partial) were subsequently performed, and verified that RCIC was operable throughout the event.

4. On HPCI initiation during this event, the vacuum pump started, the auxiliary oil pump started, the HPCI turbine steam supply valve (HV-55-2F001) opened, and the turbine started to spin. The turbine cycled 6 times on overspeed before operator action secured the system by closing HV-55-2F001 to terminate erratic operation. The injection valves did not open because the initiation signal was not present long enough. It should be noted that the actual reactor water level never dropped below 0 ±1 inch during the scram.

   HPCI turbine speed is controlled automatically by an integrated, closed loop control system consisting of a flow controller and an electronic-hydraulic-mechanical turbine governor. The flow controller may be selected for automatic operation to produce an electrical output proportional to the difference between actual HPCI pump discharge flow and desired pump flow, or manual operation where the output is dependent upon a manual control adjusted by the operator. The turbine governor system receives the flow controller output and converts it into hydraulic-mechanical motion to position the turbine governor valve relative to the flow controller output. The turbine governor system is calibrated such that the maximum flow controller output corresponds to a specified turbine high speed rating and the minimum flow controller output corresponds to a specified turbine low speed rating.

With the HPCI system in the standby mode and the turbine at rest, the flow controller senses no flow and, thus, produces a maximum output signal calling for rated speed. Upon HPCI system initiation, a ramp generator function is initiated by the mechanical movement of the turbine stop valve. As the stop valve leaves its fully closed seat, a valve position limit switch will close a set of electrical contacts to initiate the ramp function. The flow controller output calls for maximum turbine rated speed, limited by the ramp generator, until such time that pump flow is established and reaches the setpoint of the flow controller. From this condition, the flow controller will regulate HPCI turbine speed to maintain the desired system flowrate.

PECo engineers and I&C technicians performed MRF 8909833 for troubleshooting and recalibration of the governer control system. Several voltage signals in the flow controller circuit were re-adjusted and the turbine was tested at 175 psi, 200 psi and 920 psi. Each test was successful and demonstrated the turbine would run without tripping on overspeed.

At 1:46 a.m. on November 16, 1989 the HPCI was declared operable and the unit was placed in Mode 1. At 3:21 a.m the unit was synchronized to the grid and power escalation commenced in order to continue Test Condition 6 testing.

In general, the inspector found the licensee's investigation following the event to be thorough and the noted problems were resolved. The inspector also noted operator performance during the transient was excellent and very professional.

2.3 Engineered Safety Feature (ESF) System Walkdown: (71710)

The inspectors verified the operability of portions of the 2A Emergency Diesel Generator and the Unit 2 Standby Liquid Control System by performing a walkdown of the system to confirm that system lineup procedures agree with plant drawings and the as-built configuration. These ESF system walkdowns were also conducted to identify equipment conditions that might degrade performance, to determine that instrumentation is calibrated and functioning, and to verify that valves are properly positioned and locked as appropriate. The inspectors also utilized methods prescribed in a study prepared for the NRC by Brookhaven National Laboratory using the Limerick Probabilistic Risk Assessment (PRA), to enhance the inspection activity. 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. Abbreviated system checklists in Tables 1-4 and 11-1, which identify components that are considered to have a high contribution to risk as determined in the PRA, were also used by the inspector.

The following procedures and drawings were reviewed for the 2A Emergency Diesel Generator walkdown:

Drawing M-11	Emergency Service Water Piping and Instrumentation Drawing
Drawing M-20	Fuel and Diesel Oil Storage and Transfer (Diesel Generator "A", Unit 2)
2S92.1.N (Col. 1)	Equipment Alignment for 2A Diesel Generator Operation
S92.1.N	Diesel Generator Set Up for Automatic Operation
FSAR 9.5.4	Diesel Generator Fuel Oil System
FSAR 9.5.5	Diesel Generator Cooling Water System
FSAR 9.5.6	Diesel Generator Starting System
FSAR 9.5.7	Diesel Generator Lubrication System
FSAR 9.5.8	Diesel Generator Combustion Air Intake and Exhaust System

The inspector found the system to be in good condition and properly aligned. No problems were noted.

The following procedures, drawings and tests were reviewed for the Standby Liquid Control (SLC) System walkdown:

Drawing M-48	Standby Liquid Control (Unit 2)
2S48.1.A (COL)	Equipment Alignment to Place Standby Liquid Control System in Normal "Standby" Condition
IV 48	Standby Liquid Control System Instrumentation Alignment
ST-3-048-230-2	SLC Pump, Valve and Flow Test
FSAR 7.4.1.2	Standby Liquid Control System Instrumentation and Controls
T/S 3/4.1.5	Standby Liquid Control System

The inspector's walkdown of the Standby Liquid Control (SLC) system configuration determined that the as-built condition conforms to the system drawing and all valve/switch positions were as indicated and required. The associated instrumentation was functioning properly and was in current calibration. All technical specifications for SLC were being met. During the walkdown of the SLC system the inspector noted the overall condition of the system was good and no indications were evident that it would not perform it's required safety related function.

3.0 Surveillance/Special Test Observations (61726)

During this inspection period, the inspector reviewed in-progress surveillance testing as well as completed surveillance packages. The inspector verified that surveillances were performed in accordance with licensee approved procedures, plant technical specifications, and NRC Regulatory Requirements. The inspector also verified that instruments used were within calibration tolerances and that qualified technicians performed the surveillances. No problems were identified during this review.

ST-6-107-590-0	Daily Log - Common
ST-1-055-800-2	HPCI System Response Time Testing

ST-3-107-990-2 ECCS/RCIC Vessel Injection and Reporting

S55-1.D HPCI System Full Flow Fuctional Test

In addition numerous surveillance tests associated with the power ascension activities of Unit 2 were witnessed and reviewed. These tests are discussed in Section 5.2.

4.0 Maintenance Observations (62703)

The inspector reviewed the following safety related maintenance activities to verify that repairs were made in accordance with approved procedures, and in compliance with NRC regulations and recognized codes and standards. The inspector also verified that the replacement parts and quality control utilized on the repairs were in compliance with the licensee's QA program. No problems were identified during this review.

8909833 HPCI Turbine Control Troubleshooting/Recalibration

8910020 Leak Detection System Temperature Transmitter Repair

5.0 Power Ascension Test Program (PATP) Unit 2 (72300, 72301, 72302, 72400, 35501)

5.1 Overall Power Ascension Test Program

At the beginning of this report period Test Condition (TC) 3 (approximately 45 - 75% power, 75% control rod line) testing was in progress. Major testing evolutions conducted were the first high pressure coolant injection (HPCI) system injections to the reactor pressure vessel, and recirculation system one and two pump trips. TC-5 (approximately 65 - 75% power, 100% control rod line) and TC-4 (Natural Circulation) testing was conducted on November 1 and November 2, respectively. TC-6 (95 - 100% power, 100% control rod line) was entered on November 3 and at the end of the inspection period TC-6 testing was ongoing.

5.2 Power Ascension Testing Activities

The inspectors witnessed portions of the power ascension testing activities discussed below. The performance of these tests were witnessed to verify the attributes previously identified in Inspection Report No. 50-353/89-24, Section 4.3.

<u>2STP-1.3, Gaseous Effluent Sampling and Analysis</u> - On October 12, 1989 the inspector witnessed the partial performance of the following surveillance and chemistry tests:

ST-5-076-810	Unit 1 and 2, South Stack Monthly Noble Gas and Tritium Sampling and Analysis
ST-5-076-815	Unit 1 and 2, South Stack Weekly Charcoal Analysis
ST-5-076-820	Unit 1 and 2, South Stack Weekly Particulate Analysis
ST-5-076-810-0	North Stack Monthly Noble Gas and Tritium Sampling and Analysis
ST-5-076-815-0	North Stack and Hot Maintenance Shop Weekly Charcoal Analysis
ST-5-076-820-0	North Stack and Hot Maintenance Shop Weekly Particulate Analysis
CH-605	Sampling and Determining of Tritium

Data obtained during these tests was used to complete the requirements of 2STP-1.3, "Gaseous Effluent Sampling and Analysis." The inspector observed that the surveillance tests were conducted in a well controlled manner. No discrepancies were identified.

<u>2STP-25.2, Full Closure of Fastest Main Steam Isolation Valve (MSIV)</u> - On October 20, 1989, the inspector witnessed the successful conduct of the full closure of the fastest MSIV test. At approximately 66% reactor power, the 2C inboard MSIV was fast closed which resulted in approximately a 6% momentary increase in power. All acceptance criteria were satisfied.

<u>2STP-15.4, Controller Optimization During Reactor Pressure Vessel (RPV) Injection at Rated Pressure</u> - The inspector witnessed the first hot quick start of the High Pressure Coolant Injection (HPCI) system on October 22, 1989. The system started and reached rated flow of 5600 gpm to the RPV within approximately 20 seconds. No discrepancies were noted.

2STP-30.2, Recirculation Pump Trip (RPT) of Two Pumps - The inspectors witnessed the performance of test 2STP-30.2 Rev. 1, "Recirculation Pump Trip of Two Pumps." The purpose of the test was to verify the proper core flow coastdown time upon the tripping of both pumps.

The test personnel and plant operators were trained on the test performance in the plant simulator. A thorough pretest briefing of all personnel involved in the test was performed. Plant management including the site Vice President attended the briefing and ensured the operators were prepared to recognize and respond to power oscillations should they occur. The test was performed in a very well controlled and professional manner. No power oscillations were observed while in natural circulation and the operators promptly restored the recirculation pumps.

The flow coastdown time was marginally outside the acceptance criteria range; however, upon further analysis by General Electric it was determined to be acceptable as-is.

The flow coastdown was measured a second time, at a higher power level, when the recirculation pumps tripped on November 10 during an unexpected turbine trip. All flow coastdown data was acceptable during this transient.

2STP-2.1, Radiation Surveys - On November 9, 1989, with the reactor at approximately 95% rated power, the inspector witnessed Health Physics (HP) technicians conducting radiation surveys in the Unit 2 West Core Spray Pump Room. The pump room is designated as radiation zone II with a maximum design dose of $\leq$2.5 mRem/hr. All readings were well within this criterion. No discrepancies were noted.

2STP-23.4, Loss of Feedwater Heating - On November 20, 1989 with the reactor at approximately 86% rated power the inspector witnessed the conduct of 2STP-23.4 which involved loss of the 6th stage of feedwater heating. The test was successfully conducted with feedwater temperature decreasing by approximately 47 degrees Farhenheit and reactor power increasing by only 5 - 6%. The inspector noted that the pre-test briefing was thorough and that the test was conducted in a professional manner.

5.3 Power Ascension Test Results Evaluation

All startup tests for Test Conditions 3, 5, and 4 were reviewed to verify that all acceptance criteria had been satisifed, Test Exception Reports were adequately resolved, and the test results were appropriately reviewed and approved. In addition, the startup tests listed and discussed below were reviewed for the attributes identified in inspection report 50-353/89-24, Section 4.4. Except as noted below, all startup test results were found to meet the attributes referenced above.

5.3.1 Test Condition 3

2STP-1.3, "Gaseous Effluent Sampling and Analysis," results approved October 20, 1989

Offgas and Stack Monitor readings were taken and compared to the analysis of grab samples at approximately 50% of rated power. The results were determined to be acceptable.

2STP-2.1, "Radiation Surveys," results approved October 27, 1989

Two level one acceptance criteria violations were identified for the radiation doses in two areas of the plant exceeding their maximum allowable values. An area on the Traversing Incore Probe (TIP) room roof had an on-contact dose rate of 300 mR/hr during operation of the TIP system which exceeded the zone IV radiation zoning criterion of <100 mR/hr. An area in the turbine enclosure failed the zone II criterion of ≤2.5 mR/hr with a reading of 4.0 mR/hr. Both areas were subsequently rezoned and applicable drawings revised to account for the higher dose rates.

2STP-15.4, "Controller Optimization During Reactor Pressure Vessel (RPV) Injection at Rated Pressure," results approved October 27, 1989

The first hot quick start of the High Pressure Coolant Injection (HPCI) system to the reactor pressure vessel was accomplished and the HPCI pump discharge flow rate reached 5600 gpm in 19.9 seconds (acceptance criteria ≤30 seconds). All acceptance criteria were satisfied with the exception of the decay ratio of several HPCI system related variables (flow, turbine speed, and discharge pressure). The decay ratios were analyzed and accepted as is. The inspector reviewed the analysis and found it to be acceptable.

2STP-15.5, "HPCI Cold Quick Start at Rated Pressure, Condensate Storage Tank to RPV," results approved October 27, 1989

HPCI successfully reached rated flow of 5600 gpm in 22.5 seconds. All acceptance criteria were satisfied.

<u>2STP-19.2, "Process Computer Calculation," results approved October 24, 1989</u>

The test was performed at approximately 50% rated thermal power. The calculated thermal limits met the acceptance criteria and were within the limits specified by the Technical Specifications.

<u>2STP-22.2, "Pressure Regulator Response - Control and Bypass Valve Operation," results approved October 24, 1989</u>

All acceptance criteria were satisfied.

<u>2STP-24.1, "Stop Valve Testing," results approved October 20, 1989</u>

All acceptance criteria were satisfied. The inspector reviewed the time history plots for the four main stop valves tested and verified that the margin to neutron flux scram line was 31.5%, well within the acceptance criterion of at least 7.5%.

<u>2STP-25.2, "Full Closure of Fastest Main Steam Isolation Valve (MSIV)," results approved October 24, 1989</u>

At 66% rated thermal power the fastest MSIV was closed. All acceptance criteria were satisfied. The MSIV stroke time was 3.57 seconds ($\geq$ 3.0 seconds required) and the MSIV closure time was 4.05 seconds ($\leq$ 5.0 seconds required). The neutron flux margin to scram was 35.88% well within the acceptance criterion requirement of $\geq$7.5%.

<u>2STP-29.1, "Local Manual Recirculation Flow," results approved October 26, 1989</u>

At approximately 68% power and core flow of 92% rated the recirculation flow control system responded in a stable manner to step changes in generator speed demand. The extrapolated margin to scram was determined to be 13.6% core thermal power (CTP) for recirculation loop A and 14.2% CTP for Loop B (acceptance criterion $\geq$7.5% CTP).

<u>2STP-30.1, "Recirculation System One Pump Trip," results approved October 26, 1989</u>

At 70% rated thermal power one recirculation pump was tripped. The test was successful with a water level margin to avoid a high level trip of 13.2 inches (acceptance criterion $\geq$3.0 inches) and an APRM margin to avoid a scram during the pump trip recovery of 32% (acceptance criterion $\geq$7.5%).

<u>2STP-30.2, "Recirculation Pump Trip of Two Pumps," results approved November 1, 1989</u>

One Test Exception Report (TER) was written to document a Level 1 acceptance criteria failure for recirculation drive flow coastdown not being within the specified limits during the period from 1/4 to 3 seconds after the pump trip. The failure was analyzed and determined to be acceptable as is. The inspector reviewed the analysis and found it to be acceptable.

<u>2STP-34.1, "Offgas Performance Verification," results approved October 20 and 27, 1989</u>

Offgas performance was verified at approximately 50% and 70% rated thermal power. Several of the offgas system operating parameters did not meet the Level 2 acceptance criteria. These parameters were aftercondenser hydrogen concentration, cooler condenser discharge temperature and cooler condenser dewpoint. Test Exception Reports #136 and #152 were written to document the acceptance criteria failures and Plant Staff Field Report (PSFR) #660 was written to evaluate and/or investigate the out of specification data. Investigation found the hydrogen analyzer to be out of calibration. Retest following recalibration resulted in an aftercondenser hydrogen concentration which met the acceptance criteria. The TERs and PSFR remain open pending further investigation of remaining out of specification data.

<u>2STP-35.1, "Recirculation System Flow Calibration," results approved November 1, 1989</u>

All acceptance criteria were satisfied with the exception of the criterion for jet pump nozzle plugging for jet pumps 17/18 and 19/20. The calculated nozzle plugging values for these jet pumps were 0.152 and 0.123 respectfully, with an acceptance criterion of $\leq$0.12. A TER was written to document the acceptance criterion deviations and an analysis of the deviation was performed by GE San Jose. The analysis was reviewed by the inspector and found to be acceptable.

<u>2STP-36.3, "Recirculation Piping Vibration During Selecte Transients," results approved October 27, 1989</u>

The measured vibration for the recirculation piping during the double recirculation pump trip on October 24, 1989 was well within the established acceptance criteria.

2STP-99.5, "Test Plateau C - Test Condition 3," results approved November 1, 1989

The inspector reviewed the test plateau procedure to ensure that all testing required for Test Condition 3 had been accomplished and that all Test Exception Reports (TERs) remaining open could safely be carried forward into subsequent test conditions. Five TERs remained open at the end of TC-3. The inspector reviewed the TERs and determined it acceptable to allow the TERs to remain open into future test conditions.

5.3.2 Test Condition 5

2STP-9.1, "Reference Leg Temperature Comparison," results approved November 7, 1989

Consistent response of the narrow range and wide range level instrumentation was verified at reactor power of approximately 58%.

2STP-12.3, "High Power Average Power Range Monitor (APRM) Calibration," results approved November 7, 1989

The APRM channels were calibrated to read 59% core thermal power which was greater than the actual core thermal power of 58.9%. In addition, the Technical Specification limits for APRM Scram and Rod Block setpoints were verified not to be exceeded.

2STP-19.2, "Process Computer Calculation," results approved November 7, 1989

At approximately 50% rated thermal power the reactor was verified to be operating within its Technical Specification thermal limits.

2STP-22.3, "Pressure Regulator Response - Bypass Valve Operation," results approved November 7, 1989

All acceptance criteria were satisfied.

2STP-23.3, "Feedwater System Level Setpoint Changes," results approved November 7, 1989

All acceptance criteria were satisfied.

5.3.3 Test Condition 4

2STP-19.2, "Process Computer Calculation," results approved November 7, 1989

At approximately 42% power in Test Condition 4, the reactor was verified to be operating within the Technical Specification thermal limits.

2STP-23.3, "Feedwater System Level Setpoint Changes," results approved November 7, 1989

All acceptance criteria were satisfied.

5.4 Quality Assurance (QA) Interface with the Power Ascension Test Program

The inspector reviewed numerous QA Technical Monitoring reports for the period September 13 to October 27, 1989. These reports documented monitoring of various power ascension activities including the "Loss of Turbine Generator and Offsite Power" test; the "Shutdown from Outside the Control Room" test; and testing of RCIC, HPCI, MSIVs, feedwater, pressure regulator response, and relief valves at rated pressure. The inspector verified that the monitoring was conducted per Limerick Quality Division Monitoring Guideline PA-01.

The inspector also reviewed Corrective Action Request (CAR) LA89034-01 which was initiated to identify the startup group's failure to promptly review data for conformance with Level 1 acceptance criterion for 2STP-2.1, "Radiation Surveys," resulting in a failure to notify Shift Supervision that a Level 1 criterion was exceeded. A Startup Training Bulletin addressing the concerns identified in the CAR was issued on October 27, 1989 to all startup personnel. The inspector reviewed the training bulletin and discussed the issue with a licensee QA representative who stated that the corrective action has been prompt and adequate. The inspector had no further questions.

6.0 Review of Periodic and Special Reports (90713)

Upon receipt, the inspector reviewed periodic and special reports. The review included the following: inclusion of information required by the NRC; test results and/or supporting information consistent with design predictions and performance specifications; planned corrective action for resolution of problems; and reportability and validity of report information. The following periodic report was reviewed:

Monthly Operating Report - October 1989

The inspector had no questions regarding this report.

7.0 Licensee Event Report (LER) Followup (90712)

The inspector reviewed the following LERs to determine that reportability requirements were fulfilled, that immediate corrective action was taken, and that corrective action to prevent recurrence was accomplished. In accordance with the above inspection modules the inspector considers the following reports closed. The inspector had no further comments or questions except as noted.

LER Number	Subject/Comments
1-89-051*	The main control room ventilation system was inadvertently placed in a normal lineup with the chlorine detectors out of service. This is a violation of plant Technical Specifications. The error occurred due to miscommunications between the field engineers and plant operators during post modification testing on the chlorine detection system. The error was detected and corrected in one hour and twenty minutes. Upon completion of the modification testing it was determined that the chlorine detectors would have functioned if called upon during the time period in question. Thus the error was of minimal safety significance. (NCV 50-352/89-21-01)
1-89-053	A momentary vinyl chloride release occurred at a nearby chemical plant resulting in a manual control room isolation. This event was also discussed in Section 2.1. As a result of this occurrence PECo is attempting to establish a communication path between the power plant and chemical plant to facilitate handling of any future events.
1-89-054*	During a review of NRC Generic Letter 89-19 requirements regarding vessel overfill protection it was discovered that the Feedwater/Main Turbine Trips System Actuation Instrumentation Channel Check procedures did not include a check of the Channel D instrumentation. The Daily Surveillance Log, ST-6-107-590-2 was corrected for Units 1 and 2 to include the necessary check. The procedures were also reviewed to ensure all other required channel checks were included. No other problems were identified during this review. (NCV 50-352/89-21-02)

2-89-007* The reactor mode switch was placed in startup prior to restoring the fourth low pressure coolant injection (LPCI) loop to service resulting in a violation of Technical Specifications. The cause was personnel error on the part of the shift supervision. A contributing factor was that the startup procedure, GP-2, did not delineate which steps had to be followed in a mandatory sequence. The safety significance of the event was minimal since the plant was in cold shutdown, no rod withdrawal had occurred and the three other LPCI loops were operable when the mistake was discovered. The inspectors reviewed the revision to GP-2 and found the improvements to be acceptable. This event was previously reviewed and is discussed in section 2 of Combined Inspection Report 50-352/89-19 and 50-353/89-28.

2-89-008 A manual isolation valve in the Emergency Service Water (ESW) system was inadvertently left closed blocking the flow path to several emergency core cooling pump room coolers and the "B" and "D" Residual Heat Removal (RHR) pump seal and motor oil coolers. This mispositioned valve was discovered during the performance of periodic ESW system flow tests. The exact cause could not be determined but apparently was due to personnel error during previous valve positioning. The valves have been locked to prevent recurrence.

2-89-009 This is a special report required by plant Technical Specification 3.7.3.b to document Unit 2 Reactor Core Isolation Cooling (RCIC) actuations which result in water injection into the reactor vessel. Eight RCIC actuations have occurred all of which were planned injections as part of the startup test program.

2-89-010 The high pressure coolant injection (HPCI) turbine was found to be in a degraded condition due to condensate accumulations in the turbine exhaust pipe. The condensation was due to blockage of the drain pipe flow orifice (1/8" diameter). The piping was cleared using compressed air and a routine test is being written to verify the drain line flow path on a weekly basis. Additional flushing of the drain line is to be performed during the next HPCI system outage.

* These reports identify conditions which are violations of the plant Technical Specifications. The inspectors have reviewed these events and determined that they satisfy the criteria for licensee identified violations as stated in 10 CFR 2 Appendix C, Section V.G.1 and as such a Notice of Violation will not be issued.

8.0 Station Personnel Reassignments

On November 3, 1989 PECo announced personnel changes for the Limerick Station. Among the changes were individuals that must meet the requirements of ANSI/ANS-3.1-1978 "Selection and Training of Nuclear Power Plant Personnel." The qualifications and experience of the personnel listed below were evaluated by the inspector:

Name	Effective Date	Title
J. F. O'Rourke	December 1, 1989	Manager, Limerick Quality Division
L. A. Hopkins	December 4, 1989	Operations Superintendent
J. M. Armstrong	December 4, 1989	Asst. Operations Superintendent
G. D. Edward	January 1, 1990	Technical Superintendent
J. Muntz	January 1, 1990	Superintendent ISEG

The inspector determined that these personnel meet the ANSI/ANS requirements. In addition, J. Muntz meets the requirements for the position of the Superintendent of ISEG listed in Technical Specification 6.2.3.2.

9.0 Heat Stress Incident Corrective Actions

NRC Inspection Report 50-352/89-18 reviewed a personnel heat stress incident which occurred on August 29, 1989. The licensee performed a thorough root cause analysis and generated a comprehensive corrective action plan to prevent recurrence. The inspector reviewed the plan and found it to be in depth and, when fully implemented, should minimize the potential for additional incidents.

10.0 Exit Interview (30703)

The NRC resident inspectors discussed the issues in this report with the licensee throughout the inspection period, and summarized the findings at an exit meeting held with the plant manager, Mr. M. J. McCormick, Jr. on November 17, 1989. No written inspection material was provided to licensee representatives during the inspection period.