EXECUTIVE SUMMARY

Limerick Generating Station, Units 1 & 2
NRC Inspection Report 50-352/96-03, 50-353/96-03

This integrated inspection included aspects of PECO Energy operations, engineering, maintenance, and plant support. The report covers a 9-week period of resident inspection; in addition, it includes the results of announced inspections by a regional radiation specialist and regional engineering inspectors.

Operations

- Overall conduct of operations was generally well controlled and safety-conscious. Operators' performances during Unit 1 shutdown and startup activities were good.

- The use of an incorrect revision of a procedure for main turbine valve testing resulted in operators receiving average power range monitor (APRM) and rod block monitor (RBM) alarms. Although this was considered a minor issue, operators had an opportunity to identify and correct the procedural deficiency prior to performance of the testing (Section O1.2).

- Plant management recognized the significance of an event in which a short reactor period was observed during a Unit 1 approach to criticality. However, the event revealed a weakness in the coordination of the reactor startup, in that the rod pull sequence did not take into account operating constraints (Section O1.5).

- Operators responded appropriately in declaring an Unusual Event after ammonia-type odors were detected in the main control room and a high toxic chemical alarm annunciated (Section O1.6).

- A personnel error by an equipment operator resulted in all of the standby gas treatment systems being inoperable for a short period. This condition is prohibited by technical specifications, and resulted in a non-cited violation (Section O8.4).

- Personnel error during cleaning activities caused the actuation of an underfrequency relay resulting in a loss of power to an RPS/UPS power distribution panel. This caused an Engineered Safety Feature (ESF) actuation of minor consequence (Section O8.5).

Maintenance

- In general, observed maintenance work activities were found to be very well performed (Section M1.1).

- The 18 month maintenance inspection performed on the D21 emergency diesel generator was effectively controlled and included a significant level of engineering support (Section M1.2).

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- Anomalies observed during a high pressure coolant injection (HPCI) pump, valve and flow surveillance test were resolved in an expeditious manner. However, operations personnel should have been aware of the dual signal generated by the low condensate storage tank level which automatically swaps the suction path for the HPCI and RCIC suction valves (Section M1.3).

- During a surveillance test of the D21 emergency diesel generator, a "generator loss of excitation" alarm revealed ambiguities with regard to operator actions per the Alarm Response Card (ARC). The ARC was changed to removed the ambiguity (Section M1.4).

- An inadequate administrative program resulted in missing increasing the frequency of testing of the D21 emergency diesel generator (EDG) from monthly to weekly based on recent test failures. This resulted in a non-cited violation (Section M8.1).

Engineering

- PECO Energy's evaluation of the operability of turbine rotor discs was comprehensive. Additionally, comprehensive actions are resolving engineering issues such as emergency diesel generator system component problems with Agastat relays, protective relays, control switch problems, and diesel engine oil leakage problems (Sections E1.1 and E1.2).

- Cold nitrogen gas was injected into the Unit 1 D TIP to free up binding within the indexer. The adequacy of the safety evaluation and PORC review is unresolved (URI 50-352/96-03-01) pending NRC review of the final disposition of this activity by plant management (Section E2.1).

- Safety component problems with vibrating high pressure coolant injection system steam lines, and emergency diesel generator lubrication oil heat exchanger design were resolved through good engineering performance. Engineering response to licensee event reports demonstrated good communication and coordination of PECO Energy functions (Section E2.2).

- Procedures and documentation of modifications were in general good. However, temporary plant alterations (TPA) were not controlled in accordance with documented procedures, resulting in a violation of 10 CFR 50, Appendix B. Specifically, the list of TPAs in the control room did not correspond to the list maintained by the engineering organization, thus making it difficult for operators to determine the true plant configuration (Sections E3.1 and E3.2).

- PECO Energy has an effective engineering performance measurement system. The performance trend curves allow for measurement against goals and identify areas where resources must be introduced to resolve performance problems. The engineering staff is of excellent quality, and PECO Energy has a good training and qualification program. The engineering organization is goal oriented. Section objectives are set through implementation of goals derived from overall corporate goals (Sections E4 and E5).

- The activities of the Independent Safety Engineering Group (ISEG) offered effective oversight of engineering quality. The reports were comprehensive and clearly written and provided for monitoring of corrective action programs implemented as a consequence of ISEG findings (Section E7.1).

- An effective system is in place which identifies chronic engineering problems and attacks these problems effectively through "Tiger Team" multi-disciplinary groups which focus on the solution of major BOP chronic problem issues (Section E8.1)

- Failure to adequately test the control room HVAC to verify that it met the design basis of the plant, had more-than-minor consequences, since it resulted in all of the control room emergency fresh air system (CREFAS) being inoperable multiple times. Corrective actions taken were appropriate for the circumstances. This resulted in a non-cited violation (Section E8.5).

Plant Support

- The licensee continued to maintain overall effective radioactive liquid and gaseous effluent control programs (RECP) including management controls, quality assurance audits, control of liquid and gaseous effluents, calibration of radiation monitoring systems, air cleaning systems, and implementation of the Offsite Dose Calculation Manual (ODCM). However, one non-cited violation was identified, concerning insufficient action to compensate for an effluent monitor that was temporarily out of service (Section R1.1).

- From March 19, 1996, until April 11, 1996, the Limerick Physical Security Plan, a document containing safeguards information, was left unattended and was not stored in a locked security storage container. Additionally, this document was available to personnel outside the protected area, and not authorized access to safeguards information. This is an apparent violation (Section S4).

Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100 percent power. On March 24, the unit was shut down for planned maintenance. Following replacement of the D Traversing In-Core Probe (TIP) indexer, replacement of 5 safety relief valves (SRV), repair of the D residual heat removal (RHR) injection valve, and other minor maintenance, Unit 1 was returned to power operations on March 30. On March 31, power was reduced to approximately 21 percent, after operators observed turbine bypass valves opening for no apparent reason. Two Electro-Hydraulic Control (EHC) speed control cards were replaced and the power was increased to 100 percent on April 3. The plant remained at full power through the end of the inspection period except for several power reductions due to high turbine backpressure which occurred on hot days while work was being done on the cooling tower, which decreased its cooling capacity.

Unit 2 began this inspection period at 100 percent power. On April 30, an EHC leak was identified near the #3 turbine control valve. Plant power was reduced to approximately 22 percent so that the turbine could be taken off line. The leak was at a weld where an EHC pipe entered a junction box. The pipe and fitting were replaced and the plant was returned to 100 percent on May 4. The plant remained at full power through the end of the inspection period.

I. Operations

O1 Conduct of Operations[1]

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O1.2 Main Turbine Valve Testing Procedure (Unit 2)

a. Inspection Scope (71707)

The inspectors reviewed an instance where an incorrect revision of a surveillance procedure was used in the main control room for main turbine valve testing. The event occurred late on March 22, and resulted in operators receiving Average Power Range Monitor (APRM) and Rod Block Monitor (RBM) alarms when a turbine stop valve was being stroked. Results of the investigation, conducted by plant personnel, were reviewed, and various operations personnel were interviewed.

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[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

b. Observations and Findings

Operators appropriately stopped the test after the alarms were received. Plant personnel determined that on March 19, document services personnel issued an incorrect revision of the procedure to all controlled locations, including the control room, and the library. Additionally, the incorrect procedure was on the computer system. Plant management concluded that the incorrect revision of the procedure was inadvertently issued due to lack of attention to detail in ensuring that the correct procedure revision was sent electronically from engineering personnel to document services personnel.

As corrective actions, on March 23, document services personnel distributed the correct version of the procedure. Personnel confirmed that the incorrect version of the procedure had not been used at any other time. Document services personnel performed an administrative review, page-by-page, of 155 test procedures which were scheduled to be performed during the week of March 25; no discrepancies were found. Additionally, an administrative review of 37 procedures was performed to ensure that no problems would be encountered with the procedures required for the Unit 1 startup. Other corrective actions taken include: engineering personnel who handle procedure revisions were coached on the processes involved in sending revisions to document services; work groups were tasked with checking their computer directories for duplicate copies of procedure revisions, which were to be deleted if found; and, for a period of at least four months, document services personnel will print up hard copies of all procedure revisions coming from the responsible groups to assess the corrective actions taken.

c. Conclusions

The inspectors concluded that the corrective actions taken were appropriate, and considered this to be a minor issue. However, the inspectors noted that for the last year, operators had been reducing power on Unit 2 each time this surveillance was performed. This was the first instance where power was apparently not required to be reduced; operators had an opportunity to identify and correct this procedural deficiency prior to performance of the testing.

O1.3 Shutdown Observations (Unit 1) (71707)

The inspectors observed shutdown activities in the Unit 1 control room on March 24. The control room remained quiet and controlled throughout the shutdown. The operators used three part communication and the shift supervision monitored the operators in an appropriate fashion to get an overall picture of operator and equipment performance. The inspectors noted that although this shift had been trained extensively on the simulator on feedwater control, the reactor operator inadvertently caused a turbine trip signal at a reactor water level of 54 inches. The inspectors consider this matter a personnel error with no resultant safety consequences since the unit was already shut down.

O1.4 Startup Observations (Unit 1) (71707)

The inspectors observed startup activities in the Unit 1 control room on March 29. The startup was characterized by clear three-part communication between the operators and effective control by shift supervision. The mode switch was placed in startup at 12:11 P.M. A startup anomaly involving an unexpected short period occurred while bringing the reactor critical. (See Section O1.5)

O1.5 Short Reactor Period During Startup (Unit 1)

a. Inspection Scope (71707)

The inspectors reviewed an event where a short reactor period was observed during a Unit 1 approach to criticality. Results of the investigation were reviewed and the event was discussed with plant personnel.

b. Observations and Findings

On March 29, during the approach to criticality, the Unit 1 reactor operator (RO) noted an unusual short reactor period when a control rod was withdrawn one notch. The RO reinserted the rod one notch and consulted with reactor engineering personnel and shift supervision. They concluded that this rod had high worth and that the prompt jump had not been given enough time to decay normally after the rod withdrawal. All agreed to withdraw the rod one notch again, and pay close attention to reactor response. For this attempt, the RO observed an extremely short period, of less than 10 seconds, and an Intermediate Range Monitor (IRM) half scram was received; the RO immediately reinserted the rod and brought the reactor subcritical. Plant management halted the startup, and an investigation into the event was initiated.

Prior to withdrawing control rods to take the reactor critical again, plant management required a complete understanding of the event with appropriate corrective actions. The investigation concluded that the withdraw sequence for the approach to criticality was set up such that a high worth rod was being withdrawn near criticality, and that this caused the short reactor period. The second time the rod was withdrawn, the rod inadvertently stepped out two notches (double notched), which caused the second withdrawal to be of an even shorter period than the first. Plant management had, for immediate corrective action, a new withdrawal sequence developed with a designed reactor period of greater than one hundred seconds. Additionally, proper reactor response was continually confirmed and all operators were briefed on the event. Long term corrective actions included ensuring that the necessary requirements are incorporated into the procedures to ensure that operation procedure limits are reflected in core designs and rod sequences, evaluate and eliminate high worth notches, and enhance simulator training to address this type of reactivity event.

c. Conclusions

Plant management clearly appreciated the significance of this event and took the appropriate time to understand the event and take corrective action prior to recommencing the reactor startup. The briefings and written guidance for operators, concerning this event, were clear and comprehensive. However, the inspectors considered the event to exhibit a weakness in the coordination of the reactor startup, in that the original rod pull sequence, generated by PECO Energy Fuel Services, did not take into account operating constraints.

O1.6 Unusual Event Declaration (93722)

On April 25, operators in the main control room noted an ammonia-type odor. Shortly after this, a high toxic chemical concentration alarm annunciated in the control room. Operators placed the control room emergency fresh air system (CREFAS) in service in the chlorine isolation mode, and donned self contained breathing apparatus. The toxic gas analyzer indicated the presence of ammonia, formaldehyde and vinyl chloride. Chemistry personnel obtained samples of the control room air, and no detectable levels of toxic gasses were present. The shift manager reviewed the available data and declared an Unusual Event in accordance with ERP-101, Classification of Emergencies, due to a potential hazard to station operation, i.e. nearby or onsite release of potentially harmful quantities of toxic, flammable gas or chlorine.

The Unusual Event was terminated after confirmation that all control room and ventilation sample results were negative. The cause of the event was determined to be fumes released by sealant being used on the exterior of the control enclosure, which entered the control room air intake. All exterior cleaning and sealing activities were suspended pending additional evaluation. The inspectors concluded that the actions taken by operations personnel were appropriate for the circumstances. The final root cause determination and long term corrective actions will be reviewed after completion.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature (ESF) System Walkdowns (71707)

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the following ESF systems:

- Emergency Diesel Generator D21 (Unit 2)
- Residual Heat Removal System (A and C) (Unit 1)

Equipment operability, material condition, and housekeeping were acceptable in all cases. The inspectors identified no substantive concerns as a result of these walkdowns.

O7 Quality Assurance in Operations

O7.1 Licensee Self-Assessment Activities (71707)

During the inspection period, the inspectors reviewed multiple self-assessment activities, including:

- Plant Operations Review Committee (PORC) meetings
- The Nuclear Review Board (NRB) meeting on May 2, 1996

The inspectors observed that the NRB meeting was generally well conducted, and PECO Energy management was appropriately self critical. The inspectors found that the discussion of the Unit 1 short reactor period event (see Section O1.5) was particularly thorough and considered operations, engineering, and maintenance aspects of the issue.

O8 Miscellaneous Operations Issues (90712)

O8.1 (Closed) LER 1-96-003, Revision 00, Engineered Safety Feature Actuations Due to a Loss of Power to an RPS/UPS Power Distribution Panel Caused by the Spurious Actuation of an Underfrequency Relay

This event was reviewed in NRC Combined Integrated Inspection Report Nos. 50-352/96-01 and 50-353/96-01.

O8.2 (Closed) LER 1-96-004, Revision 00, Reactor Scram Signal While in Hot Shutdown Due to Operator Error During Depressurization

This event was reviewed in NRC Combined Integrated Inspection Report Nos. 50-352/96-01 and 50-353/96-01.

O8.3 (Closed) LER 1-96-007, Revision 00, Trip of Fuel Pool Cooling Pumps Resulting in Loss of Core Circulation and Decay Heat Removal Due to Insufficient Procedural Guidance

This event was reviewed in NRC Combined Integrated Inspection Report Nos. 50-352/96-01 and 50-353/96-01. The inspectors considered this to be a minor issue.

O8.4 (Closed) LER 2-96-001, Revision 00, Condition Prohibited by Technical Specifications in that Two Independent Standby Gas Treatment Subsystems were Inoperable due to Personnel Error

On February 20, while the common plant B standby gas treatment (SBGT) system was inoperable for scheduled outage work, the A SBGT system tripped when an equipment operator (EO) inadvertently opened breakers on an incorrect motor control center (MCC). The EO was supposed to open breakers associated with the B SBGT system, but mistakenly went to the wrong MCC. Within 4 minutes the A SBGT system was returned to operation. The event was reported for Unit 2 as a condition prohibited by technical specifications (TS), since TS require SBGT to be operable in Operational Conditions 1, 2, and 3. At the time, Unit 2 was in

Operational Condition 1, and Unit 1 was in Operational Condition 5. Plant management concluded that the cause of the event was personnel error resulting from less than adequate self check by the EO. Corrective actions included counselling the EO, and conducting standdown meetings with each operations shift, where emphasis was placed on using proper Event Free Operations practices.

The inspectors concluded that this failure to follow procedures, specifically the Clearance and Tagging Manual, had more-than-minor consequences, since it resulted in all of the SBGT system being inoperable. Corrective actions taken were appropriate for the circumstances. In accordance with Section VII.B.1. of the NRC Enforcement Policy, this violation is non-cited.

08.5 (Closed) LER 2-96-002, Revision 00, Engineered Safety feature Actuation Due to a Loss of Power to an RPS/UPS Power Distribution Panel Caused by an Inadvertent Actuation of an Underfrequency Relay

On March 15, an RPS/UPS power distribution panel lost power resulting in automatic actuations of the Unit 2 primary containment and reactor vessel isolation control system, an engineered safety feature. The most probable cause of this event was determined to be personnel error, during cleaning activities, resulting in an inadvertent actuation of an underfrequency relay. The actuation of the underfrequency relay caused a loss of power to the RPS/UPS power distribution panel. Initial corrective actions were to restore the affected systems. Long term corrective actions include creating, as necessary, additional physical barriers around the RPS/UPS inverters, and evaluating actions to prevent initiation of other sensitive equipment prior to the next station housekeeping day. The inspectors considered this to be a minor issue.

08.6 INPO 1995 Evaluation

During this inspection period, the inspectors reviewed the INPO Limerick Generating Station September 1995 Evaluation. The inspectors noted that the report detailed many beneficial practices and accomplishments, of which the inspectors were aware. Additionally, the report listed a few areas in need of improvement; the inspectors were also aware of these issues, none of which had major safety consequences. No additional regional followup is planned.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703)

The inspectors observed all or portions of the following work activities:

- repack of Unit 1 RHR minflow valve
- inspection of Unit 1 RHR discharge check valve
- work on Unit 1 RHR isolation valve
- Unit 1 remote shutdown panel switch troubleshooting
- Unit 2 EDG D21 18 month inspection

b. Observations and Findings

The inspectors found the work performed for these activities to be very good. Good involvement between maintenance personnel and the system managers and heath physics personnel was observed. Maintenance workers were knowledgeable of the activities, and work packages were appropriately used at the work location.

c. Conclusions on Conduct of Maintenance

Maintenance activities were completed by knowledgeable personnel with good coordination with the appropriate personnel.

M1.2 Examination/Maintenance of D21 Emergency Diesel Generator (Unit 2)

a. Inspection Scope (62703)

The inspectors reviewed the conduct of the planned 18 month periodic maintenance inspection performed on the D21 emergency diesel generator (EDG). The inspection included a review of Limerick Maintenance Procedure M-020-024, Diesel Engine 18 Month Examination and General Maintenance, Revision 6.

b. Observations and Findings

During the period April 29 through May 6, maintenance personnel performed inspections, testing and general maintenance on the D21 EDG. Following the inspections, an extended run-in of the EDG was conducted, and then a 24 hour endurance run was performed.

The inspectors observed that the maintenance work was generally well controlled and conducted in accordance with procedures. The post-maintenance run-in and inspection of the EDG were appropriately detailed. The 24 hour endurance run was satisfactorily completed and demonstrated that the EDG was capable of performing its required safety functions. Throughout the maintenance and testing, the inspectors noted a high level of involvement by the system manager. No concerns were identified during the review of the maintenance procedure.

c. Conclusions

The inspectors concluded that the 18 month examination and maintenance of the D21 EDG, and the follow-up testing and inspection, were effectively controlled and included a significant level of engineering support.

M1.3 HPCI Pump, Valve and Flow monthly surveillance test

a. Inspection Scope (61726)

The inspectors observed the High Pressure Coolant Injection (HPCI) pump, valve and flow surveillance test (ST-6-055-230-2) on March 29.

b. Observations and Findings

Upon initiation, the system experienced perturbations due to the presence of air in the suction piping. The HPCI turbine steam admission valve cycled, the auxiliary oil pump cycled, and the pump suction valve swapped over from taking suction from the condensate storage tank to taking suction from the suppression pool. The shift supervisor immediately ordered the reactor operator to trip the turbine in order to troubleshoot the problem. The system was realigned and the HPCI system manager initiated the troubleshooting procedures. Later that day the inspectors walked down the HPCI piping locally and then again verified the alignment in the control room. The inspector noted that the Reactor Core Isolation Cooling (RCIC) pump suction valve had also swapped position upon receiving a low suction signal. The RCIC system was aligned to take a suction from the suppression pool which is not its normal source. The inspectors brought this to the attention of the operators who immediately corrected the valve lineup.

c. Conclusions

The shift supervisor acted promptly by immediately removing the HPCI system from service when the turbine steam admission valves began to cycle. The corrective actions taken by the system manager to develop a more complete fill and vent procedure were adequate, however the inspectors concluded that operations personnel should have been aware of the dual signal generated by the low condensate storage tank level which automatically swaps the suction path for the HPCI and RCIC suction valves.

M1.4 Emergency Diesel Generator (D21) Surveillance Test

a. Inspection Scope (61726)

The inspectors observed the Emergency Diesel Generator (D21) weekly surveillance test (ST-6-092-311-2). This surveillance test was being performed weekly as required by the TS Surveillance Requirement 4.8.1.1.2.a.

b. Observations and Findings

The EDG D21 was given a start signal and a local alarm (generator loss of excitation) came in as expected. At 900 rpm the alarm was acknowledged and expected to reset. When the alarm did not reset the EO consulted the Alarm Response Card (ARC) which indicated that the EDG should be shut down. Because this particular alarm had previously come in on several occasions, the control room reactor operator indicated that the alarm was probably the result of a stuck relay. The system manager and the floor shift supervisor arrived at the EDG after an EO had already tapped on the stuck relay, thereby clearing the alarm. The inspector's primary concern was the confusion regarding whose responsibility it was to shut down the diesel and when per the ARC. The floor shift supervisor had the EDG shut down until troubleshooting could be completed. The relay was replaced and the surveillance was completed that evening.

c. Conclusions

The inspectors were concerned about the confusion regarding shutting down the EDG and noted that the ARC for Unit 1 EDGs is different than that for Unit 2 EDGs which could lead to confusion. This issue will be tracked as an inspector follow-up item pending NRC review of the final corrective actions (IFI 50-353/96-03).

M2 Maintenance and Material Condition of Faci,ities and Equipment

M2.1 RHR Injection Valve Pressure Locking Modification

a. Inspection Scope (62703)

The inspector observed maintenance work associated with the Unit 1 17D RHR Injection isolation valve modification. Maintenance personnel closed off the bypass line which was originally installed to mitigate the effects of pressure locking and drilled a hole in the upstream side of the double disk valve in order to equalize pressure on both sides of the flex wedge gate valve.

Observations and Findings

The maintenance personnel removed the disk from the valve and then performed a smoothing operation on the disk seating surface in order to aid in better disk seating. A hole was then drilled in the disk to mitigate the possible effects of pressure locking by equalizing the pressure between the upstream side and the internals of the valve. The modification provided a more reliable and accessible pressure locking fix for the 17D RHR valve.

Conclusions

The inspectors concluded that the maintenance personnel appropriately took a great deal of time ensuring the apparatus to be used in smoothing the disk was aligned correctly, thus ensuring an efficient work process.

M8 Miscellaneous Maintenance Issues (90712)

M8.1 (Closed) LER 50-353/96003, Rev. 00, Failure to Perform Accelerated Surveillance Testing of a Unit 2 Emergency Diesel Generator Due to an Inadequate Evaluation Program

On March 21, PECO Energy personnel discovered that surveillance testing of the Unit 2 D21 Emergency Diesel (EDG) had not been performed at the frequency of at least once per seven days as required by Technical Specifications (TS) based on the occurrence of 2 EDG valid failures within the last 20 valid demands. On February 24, 1996, while performing the D21 EDG monthly operability test, D21 was manually shut down by operations personnel due to the inability of the EDG to control load. This constituted a valid EDG failure and which required a special report to be submitted to the NRC. While preparing the Special Report to the NRC pertaining to the February 24, 1996, start failure, PECO Energy personnel ascertained that this was the second failure of the D21 EDG within the last 20 valid demands. A previous start failure had been reported to the NRC in a Special Report dated December 28, 1995. TS Surveillance Requirement (SR) 4.8.1.1.2.a requires in part the frequency of the specified EDG surveillance testing be increased from "at least once per 31 days" to "at least once per 7 days" if two or more failures occur in the last 20 valid demands. Since the second failure had occurred on February 24, the next performance of the TS SR was due by March 2. The SR for D21 EDG was successfully performed on February 29 per the monthly surveillance schedule; however, the next required performance of the SR was due by March 7. Since it was not recognized that the D21 EDG surveillance frequency should have been increased the missed TS SR went unnoticed until March 21.

The primary cause of this event was an inadequate administrative program to ensure that EDG testing is promptly evaluated to determine if an EDG failure occurred and if increased testing is required. On March 21, operations personnel took appropriate actions for the inoperable D21 EDG by testing the EDG per TS SR 4.8.1.1.a. The D21 EDG was declared operable and the testing frequency of the D21 EDG remains at the seven day frequency per the TS SR. The program and associated implementing documents for performing EDG failure evaluations will be reviewed and enhanced as necessary. Until the final corrective actions are in place, operations personnel have been instructed to notify shift supervision and the EDG system manager of potential EDG failures to ensure timely evaluation of the test data.

Based on the inspector's review of the licensee-identified missed surveillance, the corrective actions specified, and the fact that when called upon to start on March 21, the D21 EDG started and was fully loaded, the failure to comply with TS SR 4.8.1.1.2.a constitutes a violation of minor significance and is being treated as a non-cited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

M8.2 (Closed) LER 1-96-008, Revision 00, High Pressure Coolant Injection System Isolation, an ESF Actuation and Condition Which Could Have Prevented Its Intended Safety Function, Due to a Personnel Error

This event occurred on March 3, and was initially reviewed in NRC Combined Integrated Inspection Report Nos. 50-352/96-01 and 50-353/96-01. Investigation of this event by plant personnel concluded that the most probable cause of the HPCI system isolation was personnel error leading to the performance of test steps out of sequence. Corrective actions included restarting the system immediately and the issuing of an event training bulletin which discussed the event. The inspectors considered this to be a minor issue because it had no actual impact on safety, was not suggestive of a programmatic problem, and the system was properly restored within a short period of time.

III. Engineering

E1 Conduct of Engineering

E1.1 Major Modifications - Turbine Rotor Replacement (37550)

a. Inspection Scope

The inspectors reviewed the Limerick Generating Station (LGS) program to replace the Unit 1 and Unit 2 turbine rotors. The review included the assessment of operability of the present rotors, with known defects in the disc keyways, until replacement of Unit 1 begins at the next refueling outage.

b. Observations and Findings

On the basis of the discovery of turbine disc degradation during the rotor inspection at the last refueling outage, PECO Energy performed probabilistic assessments which determined that the turbine rotor discs would not fail over the remaining refueling cycle.

The inspector interviewed the LGS system engineer and the headquarters engineer responsible for the operability assessments, and found that the conclusion was based on a comprehensive evaluation by General Electric Company and PECO Energy, based on crack growth evaluations, supplemented by materials testing and operating experience on Boiling Water Reactor (BWR) systems. The acceptance of the GE methodology has been reviewed by NRC staff and found acceptable for use in establishing maintenance and inspection schedules for specific turbine systems (NUREG-1048).

The inspector reviewed the results of ultrasonic inspections that revealed many crack-like defects emanating from the turbine disc keyways. Some of the discovered flaws were as large as 0.4 inches. The evaluation of flaw sizes presently found in the Unit 1 turbine rotor indicates a probability of disk failure less than 10^{-5} per year, the general minimum requirement for loading the turbine and bringing the system on line.

c. Conclusions

PECO Energy has comprehensively evaluated the probability of disc burst in the Unit 1 turbine rotor and found it to be less than the level accepted by the NRC staff.

E1.2 Engineering Issue Resolution - Emergency Diesel Generator (EDG) System Component Problems (37550)

a. Inspection Scope

The inspectors reviewed the EDG system electrical and control system component failure history to assess actions taken by LGS engineering toward evaluation and solution of chronic EDG component problems.

b. Findings and Observations

Four types of significant component problems were experienced with LGS EDG system electrical and control system components during the current Systematic Assessment of Licensee Performance (SALP) period:

1) Agastat Relay Problems

Since March 1995, LGS had experienced three undervoltage (Agastat) relay failures on diesel generator buses. These relays were in the normally energized condition to detect the loss of bus voltages on the 4.16 kV safety buses on Unit 1. PECO Energy's Valley Forge Laboratory identified no problem with the first relay, high contact resistance with the second relay, and incorrect spring adjustment of the third relay. The Laboratory concluded that the relays did not fail due to thermal degradation or aging.

LGS's chronic component program had identified 3950 Agastat relays for tracking and replacement. 30 Agastat relays are installed in the EDGs control logic circuits, in addition to bus undervoltage relays installed on the 4.16 kV safety buses. All EDGs' undervoltage relays were replaced in early 1995, and the remaining EDGs' logic circuit relays were scheduled for replacement prior to the end of service life. The EDG relay preventive maintenance program determined that the critical undervoltage Agastat relays were more prone to contact oxidation, and were surveillance tested on a bi-monthly basis to ensure system reliability. The licensee had an excellent program for trending and replacing aging Agastat relays. Root causes of relay failure were determined by the licensee, and appropriate replacement, trending, and testing programs used to predict and preclude future failures were established.

2) Isolated Protective Relay Problems

Two overvoltage relays (device 159) failed during the past three years. The relays provide signals to breaker logic to close the EDG output breaker on the respective bus. In 1993, the first relay failure, on EDG D11, was due to worn and pitted contacts. In November 1995, a similar type of relay on EDG D12 was found outside its calibration. The corporate laboratory determined the root cause of the second failure to be due to out-of-calibration test equipment used to calibrate the relay. The licensee took appropriate corrective action to ensure all devices were properly adjusted and the test equipment was recalibrated.

Other EDG system component failures revealed that the Square-D relays (Class 8501 Type KPD13 11 pin 3 pole) used in the EDG manual mode control circuitry had been replaced with a redesigned model. The corporate laboratory determined that the relay (device LSA, on EDG D13) contact failed to operate due to poor design. The licensee replaced all similar Square-D relays with improved designs. All control relays in the safety circuits were replaced. No subsequent failures have been experienced to-date. Relays used in the alarm function are replaced on an as-fail basis.

Other failures included isolated control relays (Telemechanique type device CRA) used in redundant diesel start logic, and a recent diesel generator loss of field relay. The inspector determined that the licensee was closely trending the control relay failures and corrective action to determine the cause of the loss of field relay.

The EDG relay failures are trended and replacements made to preclude further problems. The inspector found the EDG system manager to be knowledgeable in his assigned system responsibilities.

3) Isolated Control Switch Problems

The inspector found two instances of inoperative EDG system control switches for which the licensee identified and took appropriate corrective actions. The licensee identified another significant component problem on D11, in July 1995, due to rusted switch contacts in the EDG pressure switches (PSL-GA-110A-1, 2 and 3). The licensee replaced these switches and inspected all similar switches.

On April 10, 1996, while performing routine biennial surveillance testing to verify operability of the safety relief valves at the remote shutdown panel (RSP) of Unit 1, the licensee found several emergency transfer switches' contacts (GE type SB-9) to have a high resistance in the range of 40 to 180 ohms. These switch contacts were cleaned and tested to be operable and the affected systems returned to service. The licensee also found two other instances in Unit 1 (1994 and 1996), where similar switch contacts were found with high resistance. These contacts were also cleaned to address the high resistance problems. These control switch contacts are normally relied upon to energize various safety systems to shut down the plant in the event of a fire in the control room.

The inspectors interviewed the electrical and instruments and control (I&C) preventive maintenance staff and found that appropriate technical assistance was being provided by the engineering staff. Maintenance staff members were knowledgeable of the identified component problems and their resolutions.

The inspectors concluded that, with the exception of the remote shutdown control switch problems, all other corrective actions were being implemented. The inspector considered this isolated case to be a minor weakness in the licensee's predictive and preventive program.

4) Emergency Diesel Generator Lubrication Problems

The inspector found that diesel oil leaks continue to be a concern during and after the monthly operability runs. The oil leaks exist at two locations on the EDGs; at the diesel exhaust line connection to the turbo exhaust line and under the engine bottom housing. The licensee is monitoring the oil leaks and attempting corrective action by using alternate gasket designs and materials. The licensee is addressing the EDG oil leakage problem by appropriate means.

c. Overall Conclusions

The inspectors found that appropriate actions are being taken by LGS engineering toward evaluation and solution of chronic EDG component problems.

The licensee has an excellent program for trending and replacing aging Agastat relays. Root causes of relay failure were determined by the licensee, and appropriate replacement, trending, and testing programs used to predict and preclude future failures were established. EDG relay failures are trended by the licensee and replacements are made to preclude further problems.

With the exception of the remote shutdown control switch problems, all corrective actions were being properly implemented. The inspector considered this isolated case to be a minor weakness in the predictive and preventive program.

The licensee is addressing the EDG oil leakage problem by monitoring the leakage with alternative oil line gasket designs.

E1.3 Safety-Related Engineering Backlog (37551)

During this inspection period, the inspectors reviewed a computer printout of the outstanding safety-related engineering backlog. This review was performed to determine if there were any outstanding engineering activities or combinations of activities which might have an adverse effect on plant operations or affect any system's operability. Based on this review, the inspectors concluded that the backlog of safety-related engineering items contains no single item or combinations of items which would have an adverse effect on plant operations or affect system operability.

E2 Engineering Support of Facilities and Equipment

E2.1 Traversing In-Core Probe Installation (37551)

a. Inspection Scope

The inspectors reviewed the engineering procedure for injection of gaseous nitrogen to the Unit 1 D Traversing In-Core Probe (TIP). This special procedure (SP-S-081-1, Revision 0) was developed to alleviate the expansion of the thermally bound Geneva gear that drives the TIP indexer which allows for full neutron mapping of the core.

b. Observations and Findings

On March 25, the D TIP indexer was replaced due to the binding of the Geneva gear in the indexer. The PECO Energy engineering team determined the indexer cam was binding due to thermal expansion of the Geneva gear. A plan was developed to inject gaseous nitrogen into the TIP machine to reduce the mechanical component's temperature and to rotate the indexer which selects the sections of the core to be mapped. A mock-up of the TIP piping and instrumentation was built at PECO Energy's Valley Forge Laboratory and the limiting variables of the sensitive components were investigated and incorporated into a test procedure. The two primary containment isolation valves were modeled as steel blocks to simulate heat sinks in the mock-up since there was not enough time to obtain the actual valves for the test.

The inspectors attended Plant Operations Review Committee (PORC) meetings convened to review the 10 CFR 50.59 safety evaluation of this evolution. The safety evaluation was written to address the changes to the facility and the test to be performed which were not previously described in the UFSAR. The safety evaluation also addressed the operability of the primary containment isolation valves (shear valve and ball valve) at cryogenic temperatures. The inspectors reviewed the procedure and the 50.59 safety evaluation and questioned engineering personnel on the operability of the elastomer parts in the ball valve. The engineering staff, on the basis of vendor assurance that the valve elastomers were cryogenically viable and results of heat transfer tests of the system mock-up, was confident based on engineering judgement that operability had been established.

The inspectors noted that plant personnel relied on the vendor's opinion of primary containment valve operability as reflected in a letter from General Electric Nuclear Energy. The letter from GE Nuclear Energy stated that the ball valve was used in cryogenic applications, but provided no quantitative basis for the judgement. Also, the shear valve vendor cited 40 degrees on their technical drawing as a limiting temperature for its component, but expressed confidence that the valve would operate under cryogenic conditions.

c. Conclusions

The inspectors found the initiative to investigate the effect of cryogenic temperatures on the operability of the system was comprehensive with respect to the consideration of all technical factors relating to operability of the actual system. There were technical areas for which PORC relied heavily on the qualitative assessments of the vendor (General Electric) in the absence of quantitative evidence. The inspectors noted that the safety evaluation was confirmed on the basis of mixed levels of comprehensiveness; a confirmatory experiment demonstrating the heat conduction performance of the system, engineering judgement, and a substantiation by the vendor with limited practical corroborative evidence. The inspectors continued to question the vendor information regarding the cryogenic performance of the primary containment valves and requested more substantive material from engineering personnel. PECO Energy's engineering staff pursued this with GE and provided the inspectors with some of the test data and background information from GE's sub-vendors. This new information provides a more substantial basis for the test and the inspectors consider the overall justification to be adequate.

The inspectors also noted however, the PORC members did not adequately pursue the operability aspect of the primary containment valves, and accepted engineering judgement and vendor assurance as a basis for valve operability. Once the additional information was received the inspector noted that the vendor had inaccurately characterized one of the elastomer materials used in the ball valve construction. The inspectors were concerned about the overall adequacy of the engineering safety evaluation and PORC's review of it, especially considering the original inaccurate information supplied by the vendor. This item will remain unresolved pending NRC's review of the final disposition of this activity by plant management (URI 50-352/96-03-01).

E2.2 Safety System Component Problems (37550)

E2.2.1 Unit 1 High Pressure Coolant Injection System Steam Line Vibration

a. Inspection Scope

The inspector reviewed LGS's ongoing activities in assessing and resolving a nonconforming condition on the High Pressure Coolant Injection (HPCI) System. The issue was previously described in IR 50-352/353/94-24, 50-352/353/95-18, and involves vibration of the Unit 1 HPCI turbine steam inlet line that has resulted in damage to a pipe support. The review effort included discussions with the engineer responsible for this issue, and a walkdown of the affected piping and supports.

b. Observations and Findings

The inspector discussed the progress made in resolving this issue with the lead design engineer. The engineer indicated that the vibration present on the Unit 1 HPCI steam line is believed to have existed since original plant start-up. LGS Specification 8031-P-363, "Specification for Test Requirements for Steady State Vibration Testing of ASME Section III... Piping for the Limerick Generating Station," includes acceptance criteria that were used during original plant start-up to verify that steady state vibratory levels of piping systems, including the HPCI steam line, were within acceptable limits.

LGS recently completed a one year period during which vibratory accelerations and displacements were measured at two points on the piping during varying plant conditions; i.e., approach to shutdown, start-up, and at intermittent power levels. The vibration measurements are now being evaluated and will be used to reassess the support configuration of the piping, and develop a modification to eliminate the vibration. LGS indicated that preliminary review of the data shows vibration levels are well within the negligible range of Specification 8031-P-363.

c. Conclusions

The inspector determined that LGS demonstrated good engineering performance in taking appropriate actions to ensure the continued operability of the HPCI system, and is working towards assessing the magnitude of the vibration, reanalyzing the system, and developing a modification to eliminate the vibration.

E2.2.2 Emergency Diesel Generator Lube Oil Heat Exchanger Design Issue

a. Inspection Scope

The inspector reviewed LGS's and PECO Energy's Corporate Engineering activities in assessing and resolving a concern with the lubricating oil (LO) heat exchangers on the EDGs. PECO Energy identified this concern while monitoring the heat exchanger performance in response to Generic Letter 89-13, "Service Water Problems Affecting Safety-Related Equipment."

b. Observations and Findings

The inspector found that PECO Energy identified a potential LO heat exchanger design error while measuring heat exchanger performance during recent EDG surveillance testing. Specifically, PECO Energy, and its technical consultants, determined that the heat exchanger vendor erred in calculating the available heat transfer area of the tubes, resulting in less design margin than assumed when the EDG was procured.

This issue is significant when assuming maximum heat exchanger tube fouling coincident with maximum spray pond temperature. The heat exchangers cool the oil using Emergency Service Water from the spray pond. PECO Energy promptly evaluated the impact of the error on LGS EDGs, and confirmed the EDGs were currently operable at and above the Technical Specification (TS) maximum spray pond temperature. In addition, LGS is taking pre-emptive measures, consisting of cleaning all EDG heat exchangers prior to the end of this coming June, to ensure that tube fouling will not challenge the heat exchanger capacity should the spray pond temperature approach maximum TS limits during the summer months.

PECO Energy is validating its findings, and provided verbal notification of the potential design discrepancy to Fairbanks Morse (FM), the EDG vendor. Additionally, PECO Energy is developing a technical letter, to be sent to FM, describing the details of the suspected design error so that FM can assess potential generic implications. In response to the inspector's request, PECO Energy will provide the NRC with a copy of the letter, when issued.

c. <u>Conclusions</u>

The inspector concluded that LGS and PECO Energy demonstrated good engineering performance in monitoring the performance of the EDG heat exchangers, identifying the potential design error, and implementing pre-emptive measures to ensure continued EDG operability.

E2.3 <u>Engineering Response to Licensee Event Reports (37550)</u>

a. <u>Inspection Scope</u>

The inspector assessed site engineering performance in evaluating and developing corrective actions, and in communicating with other disciplines, for events reported in accordance with 10 CFR 50.73.

b. <u>Observations and Findings</u>

Based on a list of events occurring over the past year, the inspector selected 2 events for detailed review:

- LER 95-010: Unit 1; manual isolation of Reactor Enclosure (RE) Secondary Containment (SC) due to low RE SC differential pressure.

- LER 95-006: Unit 2; Inadvertent Division 2 LOCA signal during performance of a surveillance test due to loose screws on an electrical bus.

LGS Engineering demonstrated very good performance in determining the root cause of the events, and in developing and implementing appropriate corrective actions to preclude recurrence. The response to LER 95-006 was especially good. Engineering determined that the inadvertent LOCA signal was caused by loose screws on a common signal bus that resulted in a momentary loss of power to the bus. To ensure this condition did not exist in similar electrical installations in the plant, LGS developed minimum and maximum installation torque requirements based on testing performed at its corporate laboratories. Engineering used the test results to develop an inspection plan that maintenance personnel used to ensure similar equipment was properly installed.

c. Conclusions

The inspector concluded that LGS Engineering demonstrated very good performance in responding to these two events. Additionally, engineering exhibited good communication and coordination with the corporate laboratories and plant maintenance in developing and implementing an inspection plan in response to LER 95-006.

E3 Engineering Procedures and Documentation

E3.1 Modification Procedures (37550)

a. Inspection Scope

The inspector assessed LGS's process for performing and controlling plant modifications. This review included discussions with LGS management and engineering personnel, review of selected plant modification procedures, and detailed review of four selected plant modifications.

b. Observations and Findings

LGS has a Modification Manual, MOD-CM-1, that provides a comprehensive step-by-step description of the modification process and identifies applicable plant procedures. The inspector determined that the manual contains excellent guidance to facilitate engineering personnel's understanding of the modification process.

All modifications are initiated using an Engineering Change Request (ECR). The inspector performed detailed reviews of the following modifications:

- ECR 96-01157: Installed a bypass line to vent potential minor leakage from the LPCI injection valve to the suppression pool.
- ECR 96-01236: Installed a pressure locking modification to the LPCI injection valve.
- ECR 96-00722: Installed a pressure locking modification to RHR Service Water Heat Exchanger inlet valves.

- ECR 95-05555: Replaced a leaking valve in Demineralized Water System makeup line to the Fuel Pool Cooling System skimmer surge tank.

The ECR packages were complete, implemented per appropriate plant procedures, and received the appropriate level of review and approval. Design input documents provided good technical descriptions of the modifications, and accurately reflected the system design basis described in the Updated Final Safety Analysis Report (UFSAR). The 50.59 evaluations were technically adequate. The appropriate procedures, drawings, design basis documents, and sections of the UFSAR were revised to reflect the modifications.

c. Conclusions

LGS demonstrated good performance in developing and implementing plant modifications in accordance with plant procedures, and applicable regulatory requirements.

E3.2 Temporary Plant Alteration (TPA) Procedures (37550)

a. Inspection Scope

The inspector assessed LGS's process for initiating, implementing, and controlling TPAs. This effort included a general review of active TPAs installed in the plant, discussions with engineering and operations personnel, and detailed reviews and walk-downs of two TPAs.

b. Observations and Findings

Similar to modifications, TPAs are processed using ECRs. A list provided by LGS indicated there were 6 TPAs installed in Unit 1, 5 in Unit 2, and 4 common to both units. The large majority of installed TPAs are not safety-related, and, for each, a removal date has been established. LGS provided a list describing, for each TPA, the responsible organization, the removal mechanism (e.g., work order, modification), the date of installation, and the estimated removal date.

Two TPAs were selected for detailed review and walk-down:

- ECR 95-04975: Provided for installation of temporary pressure gages to the Unit 1 and Unit 2 RHR Suction Lines.

- ECR 96-01253: Installed a recorder to continuously trend line pressure on the 1A Core Spray injection line.

The TPAs were initiated and implemented per appropriate plant procedures, and the ECR packages reflected appropriate system design bases. Plant Operations Review Committee (PORC) review and approval was performed when necessary. Independent verifications were specified and performed as required for installation and removal. Appropriate post-installation and post-removal testing was specified in the ECR package.

The TPAs were installed correctly, and were clearly identified with appropriate tags.

The inspector reviewed the TPA files in the main control room (MCR), and identified two examples where the controlling procedure, MOD-C-7, Revision 1, was violated. First, the procedure requires that original copies of ECR packages for installed TPAs, including the original TPA Tagging and Approval Form, be filed in the MCR. The inspector found that 4 TPA packages identified on the list of active TPAs were not in the MCR files. Second, the procedure requires that operations personnel on their shift be cognizant of TPA status. The inspector determined that the 'TPA Report' used by Operations' personnel to track and assess the impact of active TPAs did not necessarily reflect TPAs actually installed in the plant.

The inspector immediately reviewed these findings with LGS management personnel. At the time, LGS indicated that they could not explain the discrepancies, and were unable to identify with certainty all TPAs actually installed in the plant. LGS subsequently located the original TPA packages that were not initially found in the MCR, confirmed all TPAs currently installed in the plant, and took immediate corrective action to ensure that Operations shift personnel had an accurate list of installed TPAs.

The inspector determined that the first procedural violation, involving ECR packages not being maintained in the MCR, was primarily an administrative problem. However, the second procedural violation is significant because, if not corrected, it could potentially result in plant operators not adequately knowing the plant configuration. Based on information provided by LGS regarding the TPAs currently installed in the plant, the inspector determined that it was unlikely that any of these TPAs compromised plant safety.

10 CFR Part 50, Appendix B, "Quality Assurance Criteria For Nuclear Power Plants and Fuel Reprocessing Plants," specifies required criteria for quality assurance programs. Criteria V, "Instructions, Procedures, and Drawings," requires that activities affecting quality shall be prescribed by procedures, and that the activities shall be accomplished in accordance with the procedures. Further, it requires that the procedure include appropriate acceptance criteria to ensure that the activity is satisfactorily accomplished. LGS violated this requirement in that it: (1) failed to maintain TPAs in accordance with procedure MOD-C-7, Revision 1, and (2) failed to establish appropriate criteria to ensure that operators were cognizant of currently installed TPAs. (VIO 50-352, 353/96-03-02).

E3.3 Engineering Design Basis (37550)

a. Scope of Inspection

The inspectors determined the degree to which the engineering organization maintains the plant's design basis and vendor manuals current for selected significant safety systems and components to verify that the regulatory requirements and licensee commitments are properly implemented in the performance of engineering activities.

b. Observations and Findings

The inspector examined the design basis documentation and vendor manuals located in separate libraries at the site engineering and administrative offices. Based on a selected sampling by the inspector, it was found to be of good quality. The design basis documentation and vendor manual changes are controlled within a computerized document control system, similar to drawing control system, with access available at the site.

c. Conclusions

The inspector found that LGS maintains good quality design basis documents and vendor manuals at the facility site. LGS maintains control for changes in these documents through a computerized control system.

E4 Engineering Staff Knowledge and Performance (37550)

a. Scope of Inspection

The inspector reviewed the capability and performance of the LGS engineering staff in effectively implementing their assigned responsibilities.

b. Observations and Findings

The inspectors reviewed the performance trending reflected in the monthly site performance report. The performance in many critical activities of the engineering staff are measured against standards of performance identified at the beginning of the year. The performance evaluation is shown in charts and results ranging from poor to outstanding are identified in the report.

Some of the performance indicators found significant by the inspectors include Licensee Event Report (LER) cause analysis, open engineering change requests (ECRs), and plant operating history. It was noted that a general increase in the magnitude of ECR backlog was arrested during recent months. The major cause of LER reports was found to be personnel error. The plant history indicated that the large number of unplanned shutdown events experienced during 1995, had been markedly reduced during 1996.

The overall assessment of engineering performance by the licensee was generally favorable. Areas indicating developing problem trends can clearly be targeted for corrective action. If performance problems are identified, the licensee can evaluate the relative capabilities of the site and corporate engineering organizations with regard to staffing levels, experience, clearly defined responsibility, and procedures.

c. Conclusions

The inspector found the licensee had an effective engineering performance measurement system through which resources can be applied to improve areas of potential weaknesses. The inspector found the performance of the engineering organization met the established organizational goals.

E5 Engineering Staff Training and Qualification (37550)

a. Scope of Inspection

The inspector assessed the LGS program for inspector training and qualification to provide for knowledgeable and effective personnel to carry out the engineering activities at the plant site.

b. Observations and Findings

The inspector examined the engineering training and qualification of site engineering personnel and found that a comprehensive program was being followed by LGS engineering to provide training toward qualification for the assigned responsibilities of the engineering staff.

The inspector attended an overview meeting of engineering personnel held for the purpose of reviewing suggestions for the improvement of the engineering staff training. Suggestions discussed at the meeting were for specific training needs of the engineering staff necessary to carry through their responsibilities. In attendance at the meeting were engineers with responsibilities over a range of disciplines at the plant site. Also in attendance at the meeting were representatives from headquarters engineering and the Peach Bottom engineering staff.

The inspector noted that the LGS training and qualification program follows the "Guidelines for Training and Qualification of Engineering Support Personnel" ACAD 91-017 of the National Academy for Nuclear Training (Plant Area: Training and Qualification).

c. Conclusions

LGS is effectively implementing their program for the training and qualification of site engineering personnel. The training needs are periodically assessed by representatives of the engineering staff with input provided by headquarters and sister plant engineering representatives.

E6 Engineering Organization and Administration (37550)

a. Scope of Inspection

The inspector reviewed the engineering organization, the operating basis of the organization, and its ability to function effectively after reduction of organizational personnel during recent corporate "right-sizing".

b. <u>Observations and Findings</u>

The inspector reviewed the engineering organization subsequent to the "right sizing" of the engineering staff during the "NEEDS" (Nuclear Effectiveness and Efficiency Design Study) reorganization program. In discussion with engineering management, it was indicated to the inspector that the program for staff reduction and changes in organizational responsibilities (including transfer of headquarters personnel to the site) was implemented by selecting appropriate engineering personnel for the new responsibilities. In cases where engineering talent was lost through reorganization and early retirement offers, PECO was able to find replacements from outside PECO, or utilize contract engineering with the necessary experience to solve specialized problems. Management believed that the reorganization did not result in reduced engineering capability. In interviews with engineering personnel having responsibilities to solve engineering problems, the inspector was able to identify no insufficiency in engineering capability during technical discussions.

The PECO Nuclear Division retains an operating concept of setting Division objectives consistent with over-riding Corporate objectives. Progress in meeting these objectives are reviewed in monthly reports to senior management. The inspector reviewed the latest monthly performance assessment report and found the performance of engineering met the goals set for the engineering division. Units 1 and 2 both retain a high capacity factor of 88%; the emergency core cooling, high pressure coolant injection, reactor heat removal, and emergency AC power systems were found to have availability records within established goals; both Unit 1 and 2 unplanned scrams were found to be below objectives; temporary plant alterations were reduced; chemistry control was good; and backlog of non-conformance reports was reduced from 575 in 1974 to 75 at present. The effectiveness of the engineering staff is an important factor in achievement of these plant performance goals. In contrast to this, the inspector observed the trend of the causes of reported licensee events due to personal error to be increasing. The licensee recognizes this trend as warranting attention.

b. Conclusions

The performance of the LGS engineering staff, as measured by licensee performance trends of plant operation, indicates the reorganization and "right sizing" of the nuclear engineering organization has not adversely affected plant performance and safety despite some problems in the area of personnel errors.

E7 Quality Assurance in Engineering Activities

E7.1 Independent Safety Engineering Group (37550)

a. Scope of Inspection

The inspector reviewed the activities of the Independent Safety Engineering Group (ISEG) that provides oversight of critical plant engineering activities.

b. Observations and Findings

The inspector reviewed the reports published by ISEG and found them to cover a wide range of critical plant problems. Twenty two reviews were conducted by ISEG during 1995 that contained forty one recommendations. The inspector examined six of these reviews, including:

JMM 96-009	RHR Heat Exchanger Code Compliance and Operability
DCS 95-097	Review of Limerick's Leaking Main Steam Safety Relief Valves
TST 95-080	Industry experience with RCIC Governor Valve Stem Corrosion
JJB 95-106	Assessment of ECCS Suction Strainer Clogging Investigation
TST 96-008	Limerick Unit 1 RE HVAC Problems
CBA 96-029	Stuck Control Rods

The inspector found each of these reviews were related to significant plant operational issues. These issues were related to plant operational safety and included recurring problem areas identified by the licensee as chronic problem areas. The ISEG reviews provide for a comprehensive discussion of the issue or problem, including a summary, background, current status, assessment of corrective actions planned or taken, ISEG recommendations, and conclusions.

A good example of the ISEG review was found by the inspector in CBA 96-029, "Stuck Control Rods". Interest in the issue began with licensee observation that the numbers of rod problems had shown an increase. The nuclear safety significance of stuck control rods is that they create an operator challenge during rod maneuvering. The causes of stuck control rods were determined to be air intrusion and crud accumulation. ISEG found that preventive and corrective action measures were in place, but the frequency of occurrence warranted classification as a chronic problem. ISEG recommended augmentation of station actions through consideration of seven technical issues for analysis of the problem. These include Unit 1 versus Unit 2 comparisons, review of industry experience, enhancement of preventive measures, the effect of high temperature on seals, maintenance review, trend analysis, and change analysis. The ISEG recommendation was entered into the PIMS computer program via Action Request A0997964. PIMS provides for tracking of progress in implementing the recommendations.

In another example, JJB 95-106 "Assessment of ECCs Suction Strainer Clogging Investigation", the inspector found that ISEG reviewed activities related to the 1A RHR suction strainer clogging event. Small plastic fibers had clogged the suction strainer and caused pump cavitation due to low pump suction pressure. ISEG assessed the team activities and provided comments related to the event team's report. ISEG made four recommendations involving operating experience assessment, effectiveness of existing guidance for foreign material exclusion, assessment of Unit 2 suppression pool inspection results, and equipment operation and monitoring. These recommendations were placed in the PIMS and are monitored for completion.

In both these examples, in addition to the other issues reviewed by ISEG, the inspector found ISEG to provide assessments based on an in-depth study of the issues. On the basis of these assessments, ISEG provided recommendations to improve the course of the solutions to the problems. The inspector found the issues to be directly or indirectly related to safe operating performance of the facility.

c. Conclusions

The inspector found that the activities of ISEG provide good oversight of engineering quality in resolution of a wide range of engineering activities solving plant safety issues. The ISEG reports were found to be clearly written and comprehensive. The reports and a computerized monitoring system (PIMS) provide for assurance that the ISEG recommendations are followed in a timely manner.

E7.2 Plant Operations Review Committee (PORC) (37551)

During this inspection period, the inspectors attended three PORC meetings, which addressed various engineering issues. The PORC adequately met its technical specification requirements for the reviews that were conducted during these meetings.

E8 Miscellaneous Engineering Issues (37550, 90712, 92903)

E8.1 Chronic Engineering Problems

a. Scope of Inspection

The inspector reviewed the LGS Chronic Problem Resolution Program, through which chronic equipment/system problems are identified by the licensee and corrective actions are taken to ameliorate the effect of these problems on challenges to nuclear safety.

b. Observations and Findings

Through input from the operating engineering groups, independent safety engineering group observations, and trending of equipment or system failures, LGS recognized the need for expenditure of resources on resolution of chronic plant operational problems affecting the safety and efficiency of plant operations. Through this program, the critical problems are given attention together with the resources for problem solution. Several particularly critical problems have been provided with special teams, called "tiger teams," for resolution of the problem issues.

The chronic problem resolution programs include particularly significant problem areas for which "tiger teams" have been formed. Two such teams were formed to find resolutions for chronic problems with emergency diesel generators, feedwater system, main steam relief valves, and high volume air conditioning systems. Illustrative of the licensee tiger team activity, are the following two chronic problems discussed in E8.2 and E8.3.

E8.2 Feedwater Tiger Team Assessment

a. Inspection Scope

The inspector reviewed the feedwater tiger team special efforts completed to improve the system design and its performance to minimize challenges to the plant safety systems due to a loss of feedwater. The inspectors focused primarily on the engineering department activities with respect to the electrical and I&C systems/components issues to determine whether engineering was appropriately addressing and supporting the other departments to prevent the recurring systems/components failures of the station.

b. Observations and Findings

The inspectors noted that management initiated a "tiger team" process to resolve selected station critical chronic system issues. Three major plant systems that experienced several plant transients in the past three years were comprehensively evaluated to enhance overall reliability of station operation. The systems selected for this process included feedwater system, recirculating system, and turbine electro-hydraulic control systems. At the time of this inspection, the feedwater system tiger team major efforts were completed.

The inspector found that the core feedwater tiger team was a dedicated interdisciplinary group of engineering personnel including specialists with strong maintenance and operational background experience.

During the initial assessment phase of this process, the team members walked-down the complete system, and solicited suggestions/concerns from all departments, observed simulator crew performance, and reviewed the design vulnerabilities of thirteen associated sub-systems. The team also reviewed Limerick and Peach Bottom station's concerns, and other related industry operating experience. The team found that the LGS feedwater level control system (FWLCS) was susceptible to power and signal failures that could lead to plant transients.

As a result of the above process, the team recommended several short term and long term corrective actions to enhance system performance.

These were implemented in Unit 1, and similar design changes will be implemented in Unit 2 during successive outages.

Additional preventive measures in the preventive maintenance program were made to enhance overall component and system reliability. An in-depth review of testing requirements to ensure adequate testing of the system performance was also implemented.

c. Conclusion

The inspectors concluded that the licensee's "tiger team" efforts in reducing challenges on the safety systems due to loss of feedwater provided excellent results in improving the design and performance of the electrical power supplies and control system logic. The inspectors concluded that the engineering department staff appropriately supported other departments to prevent recurring systems/components failures.

E8.3 EDG Agastat Relay Replacement Program

a. Inspection Scope

The inspector reviewed the corrective action plan associated with the Agastat relays, a chronic component issue identified on the chronic system/component problem list to determine whether engineering appropriately addressed and supported the other departments to prevent recurring systems/components failures.

b. Observation and Findings

The inspector found that the LGS chronic system problem items list indicated problem component/system descriptions, recommended solutions, and ongoing corrective actions. The list is updated on a monthly basis and reviewed by plant management.

Review of ISEG-95-057, June 15, 1995 indicated seven Agastat relay failures occurred during January and February, 1995. The relay failure trend record indicated that a total of 31 station relays failed in 1995. Out of the 31 relays, 21 were found in a normally energized application.

The ISEG concluded that at Limerick, Agastat relay failures were due to contact oxidation and thermal degradation. The ISEG also compared the Limerick Agastat relay failure rate with the industry experience and determined that the failure rate at Limerick was consistent with industry experience. The licensee found that the failures of the Agastat relays were related to the construction of the relay. Contact oxidation occurred when the relays are not cycled sufficiently to maintain clean contact surfaces. The failures due to thermal degradation are inherent in the Nylon type material used for the bobbin in this relay. Since all EGP and ETR type relays are of the moveable core type, the smallest amount of debris due to thermal degradation can bind and prevent the movement of the core and contacts.

Based on the above ISEG assessment and recommendations, the licensee re-evaluated the qualified life of these relays in the post-LOCA operating condition. Based on life estimates at various temperature conditions, the licensee then developed a program to routinely replace the relays. All EDG undervoltage relays, and safety related HPCI and RCIC system relays have been replaced in Unit 1. Other system relays will be replaced periodically prior to their estimated end of life.

The inspector reviewed the Agastat relay failures trend data as of April 2, 1996, for all systems, and found that out of the total 14 failures recorded at Limerick station, 10 relays were being operated in the normally energized condition. Out of the 10 energized relays, two relays were installed on the EDG safety buses to detect the loss of voltage condition.

The inspector also reviewed the preventive maintenance (PM) program for the EDG relays and determined that the EDG system undervoltage relays were more prone to oxidation in their contacts. The licensee then surveillance tested these relays on a bi-monthly basis.

c. Conclusion

The inspectors concluded that LGS engineering appropriately addressed the chronic system/component problems of the station. Significant improvements made in the feedwater system design and PM program were noteworthy. The engineering department staff appropriately supported the other departments to predict and prevent the aging system/component issues at the station.

E8.4 Overall Conclusion

The inspector concluded that the licensee has an excellent program to monitor and replace aging components. Component failures are analyzed to determine the root cause of failures. Replacement plans, trending data, and testing programs are in place to predict and prevent failures of critical components in safety-related systems.

The inspector found the Chronic Items List at LGS to be excellent. Problem descriptions, recommended solutions, corrective actions, and status is clearly written. The list provides a basis for more in-depth inspection of corrective action implementation.

E8.5 (Closed) Unresolved Item 50-352, 353/96-01-02: concern with the operability and reliability of the CREFAS and main control room HVAC systems. Additionally (Closed) LER 1-96-006, Revision 00, 01, 02, Control Room Emergency Fresh Air System Inoperable Requiring Entry into TS 3.0.3 As a Result of Flow Switch Coordination Deficiency

a. <u>Inspection Scope</u>

The events associated with this LER, including its revisions, were reviewed in NRC Combined Integrated Inspection Report Nos. 50-352/96-01 and 50-353/96-01, and resulted in the unresolved item. The inspectors reviewed the results of the investigation, and discussed these results with engineering personnel.

b. <u>Observations and Findings</u>

Investigation by plant engineering personnel concluded that the control room HVAC system was not within the design basis of the plant. The standby control room HVAC subsystem was not fully capable of automatically starting in the event of a failure of the running subsystem due to a coordination problem in the starting of the supply and return fans. When both subsystems of the control room HVAC system were out of service and not capable of automatically starting, the control room emergency fresh air system (CREFAS) was not capable of performing its safety function to mitigate an accident. Startup testing did not adequately verify simultaneous fan starting and an incorrect station position did not adequately account for the interface between the control room HVAC system and the CREFAS.

Plant personnel took numerous, comprehensive corrective actions. The appropriate flow switch and thermal overload heater setpoints were adjusted and the system was integrally tested. The incorrect station position was deleted, and operators were informed of this action and the correct station position regarding what is required for CREFAS to be considered operable. Appropriate station procedures have been or will be revised to correct any deficiencies. A failed temperature transmitter, a defective flow element, and a defective flow switch were replaced. A review of similar HVAC systems was performed, and no similar items were identified.

c. <u>Conclusions</u>

The inspectors concluded that this failure to adequately test the control room HVAC to verify that it met the design basis of the plant, had more-than-minor consequences, since it resulted in all of the CREFAS being inoperable multiple times. Corrective actions taken were comprehensive and appropriate for the circumstances. In accordance with Section VII.B.1. of the <u>NRC Enforcement Policy</u>, this violation is non-cited. The conditions were identified by plant personnel and could not reasonably be expected to have been prevented by corrective action for a previous event.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

The purpose of this inspection was to (1) assess PECO Energy's capability to control and quantify effluent radioactive liquid, gas, and particulate releases according to the Technical Specifications (TS) and Offsite Dose Calculation Manual (ODCM) requirements, and (2) review UFSAR commitments and verify that the applicable portions of the UFSAR relative to this inspection are consistent with plant practices.

R1.1 Radioactive Liquid and Gaseous Waste Sampling and Analysis Programs

a. Inspection Scope (84750)

The inspector reviewed selected radioactive effluent control procedures and release data to verify the implementation of TS and ODCM requirements.

b. Observations and Findings

The inspector reviewed selected liquid effluent release data and weekly air iodine and particulate analysis results for the period January 1996 to April 1996. Routine samples were obtained and analyzed as required and the results met the lower limits of detection specified in the ODCM. The inspector noted that the reviewed procedures provided the required direction and guidance for implementing an effective program.

Revisions 16 and 17 of the ODCM were published since the previous inspection. Revision 16 included the addition of the auxiliary boiler exhaust stacks as a radiological effluent release point during the burn of waste oil which has been radiologically contaminated. Revision 17 included (1) the check source frequency for the Liquid Radioactive Waste Discharge Radiation Monitor was changed from a per batch basis to daily when in use; (2) the RHR Service Water and Service Water Radiation Monitor setpoint methodology was changed to incorporate a Cs-137 based setpoint versus an unidentified MPC fraction to eliminate frequent nuisance high radiation alarms due to high background caused by naturally occurring radon gas; and (3) as a result of the Land Use Census, certain gaseous effluent parameters (i.e. goat milk consumption rates, fraction of feed consumed from pasture) were changed for more realistic dose calculations. The inspector determined that these changes did not reduce the quality and function of the program, and improved the ability to control and quantify effluent releases and report reliable dose projections.

The inspector reviewed Licensee Event Report (LER) 1-96-005, "Reactor Enclosure Cooling Water System Fluid Sample Obtained and Analyzed Late". The LER revealed that the Reactor Enclosure Cooling Water (RECW) radiation monitor channel had been declared inoperable on January 18, 1996 through February 29, 1996 and that the necessary compensatory action had not been completed as required. Technical

Specification 3.3.7, Table 3.3.7.1-1, Action 72, requires that at least one grab sample of the monitored parameter be obtained and analyzed at least once per 24 hours. The LER stated that several samples had been obtained within the specified requirement but had not been analyzed within this period. The inspector reviewed the applicable procedure (ST-5-026-570-1), gamma scan log, and chemistry shift log, and the results of the analyses during the interval previously noted, and confirmed that the records indicated that some compensatory samples had not been collected or analyzed as required. During the intervals of January 22-February 10, 1996 samples had been taken within 24 hours of the previous samples but were analyzed late from as little as 2-3 minutes to as much as 5 hours. On February 7, 1996, the required compensatory sample had been taken and analyzed 1½ hours late and on January 29, 1995, the compensatory sample was collected and analyzed 5 hours late. This constitutes noncompliance with the TS requirement.

Plant management concluded that the cause of the late sample was personnel error, and the cause of the late analyses were due to inadequacies in the performance of the sampling program. Corrective actions included: the technician who obtained the sample late was counseled; the chemistry sample program was revised to shorten the sampling frequencies; and chemistry personnel were instructed to complete analyses immediately after sampling. Additionally, PECO Energy management formed an independent task force which reviewed the overall quality of the chemistry function at Limerick. Issues identified by the task force are being addressed by plant management.

The nonconformance was identified by the licensee and appears to be an isolated situation. Subsequent corrective actions were immediate and appropriate; and there was no impact on safety. In accordance with Section VII.B.1. of the NRC Enforcement Policy, this violation is non-cited.

c. Conclusions

Notwithstanding this performance discrepancy, the inspector determined that PECO Energy had generally implemented an overall effective radioactive liquid and gaseous effluent control program.

R1.2 Calibration of Radiation Monitoring Systems (RMS)

a. Inspection Scope (84750)

The inspector reviewed the calibration procedures and most recent effluent and process radiation monitor calibration and functional test results to determine the implementation of TS requirements.

b. Observations and Findings

The inspector reviewed the calibration procedures and the most recent calibration and functional test results for the following effluent and process radiation monitors:

- Air Ejector/Holdup Pipe Inlet (Noble Gas Activity Monitor),
- Control Room Emergency Fresh Air Supply Radiation Monitor,
- Hot Maintenance Shop Vent Exhaust Radiation Monitor (Noble Gas),
- Liquid Radwaste Discharge Monitor,
- Main Control Room Normal Fresh Air Supply,
- Main Steam Line Radiation Monitor,
- North Stack Effluent Radiation Monitor (Noble Gas),
- North Stack Wide Range Accident Monitor (Noble Gas),
- Service Water Radiation Monitor,
- South Stacks Effluent Radiation Monitors (Noble Gas),
- Reactor Enclosure Cooling Water Radiation Monitor, and
- RHR Service Water Radiation Monitor,

Instrument & Controls (I&C) technicians had the responsibility to perform the electronic alignment and radiological calibrations of the above radiation monitors. The calibrations and functional test results were within the acceptance criteria and were performed at the frequencies specified in the ODCM and TS, as required. The inspector toured the plant to view the RMS and related local and remote outputs and noted that the above RMS were operable during this inspection.

c. Conclusion

Based on the above review, the inspector determined that PECO Energy had an effective program to calibrate and maintain the effluent and process radiation monitors.

R1.3 Air Cleaning System

a. Inspection Scope (84750)

The inspector reviewed the procedures and most recent test results to verify the implementation of the TS requirements.

b. Observations and Findings

The inspector toured and reviewed the inspection and test results for the following air cleaning systems:

- Standby Gas Treatment System,
- Reactor Enclosure Recirculation System, and
- Control Room Emergency Fresh Air Supply System

The following test results were reviewed:

- Visual Inspections,
- In-place HEPA Leak Tests,
- In-place Charcoal Leak Tests,
- System Air Flow Tests, and
- Laboratory Tests for the Iodine Collection Efficiencies

The reviewed test results were within the TS limits and were performed at the frequencies specified in the TS. PECO Energy had implemented an effective surveillance program.

c. Conclusions

Based on this review, the inspector determined that PECO Energy implemented the TS requirements of the air cleaning systems effectively.

R6 Radiological Protection and Chemistry Organization and Administration

R6.1 Management Controls

a. Inspection Scope (84750)

The inspector reviewed organization changes, quality assurance (QA) audits, annual effluent release reports, and ODCM changes to verify the implementation of the TS requirements.

b. Observations and Findings

The inspector reviewed the organization responsible for implementing the radioactive liquid and gaseous effluent control programs and discussed with plant personnel any changes made since the last inspection conducted in April 1995. There had been no changes in the organization since the previous inspection. Sampling and analysis is conducted by Chemistry and data processing is conducted by Health Physics Support.

A QA audit of the effluent control programs is required by TS biannually. Consequently, an audit was not available for review during this inspection.

The inspector reviewed the Annual Effluent Release Reports for 1994 and 1995. The reports provided total released radioactivity for liquid and gaseous effluents and dose projection results to the public. No anomalous measurements, omissions, or trends were noted. The inspector determined that PECO Energy met the TS reporting requirements.

The inspector noted that PECO Energy published Revisions 16 and 17 of the ODCM since the previous inspection. Both revisions included Safety Evaluations in accordance with 10 CFR 50.59. The changes included the addition of a new release pathway; an improved setpoint methodology for the RHR Service Water and Service Water Radiation Monitors; increased the check source frequency for the Liquid Radioactive Waste Discharge Radiation Monitor; and revised effluent parameters as a result of the Land Use Census. The inspector reviewed the evaluations, both ODCM revisions, and the affected sections of the UFSAR and determined that the changes did not impact safety or reduce the quality and function of the program. The changes exhibit improvements in the RECP as described in Section R1.1 of this inspection report. The UFSAR was changed to coincide with the ODCM.

c. Conclusion

Based on the above review, the inspector determined that PECO Energy maintained good management controls to implement the RECP effectively.

S4 Security and Safeguards Staff Knowledge and Performance (71750)

On April 11, 1996, a licensed operator discovered that an electronic copy of the Limerick Physical Security Plan was located on a PECO Energy Company Local Area Network (LAN) computer hard drive. He immediately notified security personnel, who verified the event. This security safeguards document was available to personnel outside the protected area, and not authorized access to safeguards information. Security management immediately contacted PECO Energy computer specialists, and had them delete and write over the documents. A security investigation concluded that the document was inadvertently saved to the LAN by someone after working on the document, on March 19, 1996.

Security management concluded that this event constituted a compromise of safeguards information. Corrective actions included: the person who made the mistake was remediated and counselled; a word search was conducted for documents on the LAN, which did not identify any other documents inappropriately available; and personnel working on documents containing safeguards information are required to perform the work on a stand alone computer system which cannot be tied into the LAN.

10 CFR 73.21, Requirements for the protection of safeguards information, (d), Protection while in use or storage, requires in part that, while unattended, Safeguards Information shall be stored in a locked security storage container. From March 19, 1996, until April 11, 1996, the Limerick Physical Security Plan, a document containing safeguards information, was left unattended and was not stored in a locked security storage container. Additionally, this document was available to personnel outside the protected area, and not authorized access to safeguards information. This is an apparent violation.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of Limerick Generating Station management at the conclusion of the inspection on May 6, 1996. Plant management acknowledged the findings presented.

The inspectors asked whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X2 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspector reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspector verified that the UFSAR wording was consistent with the observed plant practices, procedure and/or parameters.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

W. MacFarland, LGS Vice President
R. Boyce, Plant Manager
M. Gallagher, Director of Engineer
W. Sproat, Director of Maintenance
J. Smugeresky, Director of Outage Management
D. LeQuia, Director of Site Support
L. Thibault, Senior Manager of Operations
J. Hutton, Operations Services Manager
M. Karney, Manager of Security
P. Berry, Manager, Health Physics Support Staff
C. Cooney, Manager, Chemistry Instrumentation
C. Gerdes, Manager, HVAC Systems Branch
L. Parlatore, Effluent Physicist, Health Physics Support Staff
J. Risteter, System Manager, Health Physics Support Staff
G. Stewart, Engineer Experience Assessment

NRC

F. Rinaldi, Limerick Project Manager

INSPECTION PROCEDURES USED

IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 84750:	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP 90712:	In-Office Review of Written Reports of Nonroutine Events at Power Reactors
IP 92901:	Followup - Operations
IP 92902:	Followup - Engineering
IP 92903:	Followup - Maintenance
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

352/96-03-01	URI	The adequacy of the safety evaluation and PORC review for the injection of cold nitrogen gas into the Unit 1 D TIP
352, 353/96-03-02	VIO	Failure to maintain TPAs in accordance with procedures as required by 10 CFR 50, Appendix B, Criterion V
353/90-03-03	IFI	Review corrective actions associated with alarm response cards for EDGs in Unit 2

Closed

50-352/96-003	LER	Engineered Safety Feature Actuations Due to a Loss of Power to an RPS/UPS Power Distribution Panel Caused by the Spurious Actuation of an Underfrequency Relay
50-352/96-004	LER	Reactor Scram Signal While in Hot Shutdown Due to Operator Error during Depressurization
50-352/96-005	LER	Reactor Enclosure Cooling Water System Fluid Sample Obtained and Analyzed Late
50-352/96-006	LER	Control Room Emergency Fresh Air System Inoperable Requiring Entry into TS 3.0.3 As a Result of Flow Switch Coordination Deficiency
50-352/96-007	LER	Trip of Fuel Pool Cooling Pumps Resulting in Loss of Core Circulation and Decay Heat Removal Due to Insufficient Procedural Guidance
50-352/96-008	LER	High Pressure Coolant Injection System Isolation, an ESF Actuation and Condition Which Could Have Prevented Its Safety Function, due to a Personnel Error
50-352/96-009	LER	Corrosion Induced Bonding Results in Main Steam System Safety Relief Valve Setpoint Drift

50-353/96-001	LER	Condition Prohibited by Technical Specifications in that Two Independent Standby Gas Treatment Subsystems were Inoperable due to Personnel Error
50-353/96-002	LER	Engineered Safety Feature Actuation Due to a Loss of Power to an RPS/UPS Power Distribution Panel Caused by an Inadvertent Actuation of an Underfrequency Relay
50-353/96-003	LER	Failure to Perform Accelerated Surveillance Testing of a Unit 2 Emergency Diesel Generator Due to and Inadequate Evaluation Program
353/96-01-02	URI	concern with the operability and reliability of the CREFAS and main control room HVAC systems

Discussed

None

LIST OF ACRONYMS USED

ARC	Alarm Response Card
APRM	Average Power Range Monitor
BWR	Boiling Water Reactor
CFR	Code of Federal Regulations
CREFAS	Control Room Emergency Fresh Air System
EA	Escalated Action
ECCS	Emergency Core Cooling System
ECR	Engineering Change Request
EDG	Emergency Diesel Generator
EHC	Electro-Hydraulic Control
EO	Equipment Operator
ESF	Engineered Safety Feature
FWLCS	Feedwater Level Control System
gpm	Gallons Per Minute
HCU	Hydraulic Control Unit
HPCI	High Pressure Coolant Injection
HVAC	Heating, Ventilation and Air Conditioning
IFI	Inspection Followup Item
IMC	Inspection Manual Chapter
IR	Inspection Report
IRM	Intermediate Range Monitor
ISEG	Independent Safety Engineering Group
LAN	Local Area Network
LER	Licensee Event Report
LGS	Limerick Generating Station
MCC	Motor Control Center
MCR	Main Control Room
NCV	Non-Cited Violation
NOV	Notice of Violation
NRB	Nuclear Review Board
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
PDR	Public Document Room
PORC	Plant Operation Review Committee
QA	Quality Assurance
QC	Quality Control
RBM	Rod Block Monitor
RCIC	Reactor Core Isolation Cooling
RECW	Reactor Enclosure Cooling Water
RHR	Residual Heat Removal
RMS	Radiation Monitoring Systems
RO	Reactor Operator
RP	Radiation Protection
RP&C	Radiological Protection and Chemistry
RSP	Remote Shutdown Panel
RWCU	Reactor Water Clean-Up
SALP	Systematic Assessment of Licensee Performance
SBGT	Standby Gas Treatment
SR	Surveillance Requirement
SRV	Safety Relief Valve
TIP	Traversing In-Core Probe

TPA	Temporary Plant Alteration
TS	Technical Specification
UE	Unusual Event
UFSAR	Updated Final Safety Analysis Report
VIO	Violation