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EXECUTIVE SUMMARY
Limerick Generating Station
Report No. 94-08

Plant Operations

Due largely to good planning and scheduling, the Unit 1 outage length was reduced from the originally planned 42 days to just under 36 days. Most work was completed on or ahead of schedule. Additionally, ALARA and safety goals were met or exceeded (Section 1.1). The overall process to ensure that the drywell was properly closed out was very good. When a large number of deficiencies were identified, the inspection procedure was appropriately performed again, and good management involvement was noted (Section 1.4). During the Unit 1 outage, conditions in Unit 2 were observed to be excellent. However, deficiencies were noted in the housekeeping conditions in both Unit 1 RHR pump rooms, in that housekeeping conditions were not returned to a good level, after completion of activities in these areas (Section 1.6).

Maintenance

During this inspection period, the inspectors reviewed the control of troubleshooting activities as part of Region I Temporary Instruction 94-01. A review of several active Troubleshooting Control Forms found them properly filled out, approved and tracked. The troubleshooting activities were well controlled (Section 2.2). The inspectors witnessed the leak seal application on the 1A reactor recirculation pump discharge isolation valve. The injection activity was well controlled with good use of the ALARA concept. Overall, the repair activities for the valve were well planned and implemented in accordance with plant procedures (Section 2.3).

Surveillance

Operational Hydrostatic Test, and Control Rod Scram Timing were reviewed during the Unit 1 refueling outage. For both of the surveillances, the inspectors observed good performance by operations personnel, with good management oversight (Section 3.1).

Engineering

Videotapes of the jet pump beam replacement and in-vessel visual inspection activities that occurred during the 1R05 refueling outage were reviewed. The videotapes were an effective tool for reviewing the results of the jet pump beam modification. Both this modification and the in-vessel visual inspections were conducted according to procedure, safely, and efficiently (Section 4.1). An unacceptable moisture content was discovered in the Unit 1 HPCI pump oil reservoir. After identification, the pump was removed from service, the oil was drained, and replaced with new oil. The system manager was very knowledgeable of the system and was appropriately involved in the corrective actions taken. Additionally, the current guidance being followed appears to be appropriate to ensure continued HPCI system availability (Section 4.3).

Miscellaneous

An unresolved item concerning the backup diesel fire pump fuel consumption was closed. Additionally, an unresolved item was closed concerning a RCIC vacuum breaker check valve temperature switch setpoint. The subject temperature switch is in the turbine exhaust vacuum breaker line whose design function is to provide an alarm in the main control room resulting from steam leakage past the vacuum breakers. In light of the changes made to the setpoint in the RCIC system, the HPCI system was evaluated for the same concern, since that system also had a similar setpoint. The inspectors consider the review of the HPCI setpoint an indication of a proactive engineering group (Section 7.0).

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DETAILS

1.0 PLANT OPERATIONS (71707, 93702)[1]

The inspectors observed that plant equipment was operated and maintained safely and in conformance with license and regulatory requirements. Control room staffing met all requirements. Operators were found alert, attentive and responded properly to annunciators and plant conditions. Operators adhered to approved procedures and understood the reasons for lighted annunciators. The inspectors reviewed control room log books for trends and activities, observed control room instrumentation for abnormalities, and verified compliance with technical specifications. Accessible areas of the plant were toured; plant conditions, activities in progress, and housekeeping conditions were observed. Additionally, selected valves and breakers were verified to be aligned correctly. Deep backshift inspection was conducted on February 27, March 5, 6, 12, and 26, 1994.

1.1 Operational Overview

Unit 1 returned to power following its fifth refueling outage, on March 12, 1994, and remained at 100% of rated power for the remainder of the period. The completion of the outage and the startup activities were reviewed as part of a Special Team Inspection 50-352/94-09 and 50-353/94-09, conducted March 1 through 15, 1994. Due largely to good planning and scheduling, the outage length was reduced from the originally planned 42 days to just under 36 days. Most work was completed on or ahead of schedule. Additionally, ALARA and safety goals were met or exceeded.

Early in the inspection period Unit 2 power was reduced to 35% of rated power in response to a trip of the 2B reactor recirculation pump (Section 1.3). Unit 2 was restored to full power, shortly after this event, and operated at that power level for the remainder of the period, with the exception of a short power reduction to 80% of rated power for a condensate pump maintenance activity.

1.2 Event Reports

On March 12, 1994, a notification was made to the NRC concerning the unplanned declaration of the Unit 1 HPCI system inoperable based on a high moisture content in the oil sump. While draining off some oil, due to a high reservoir level, personnel noticed moisture in the oil. Sampling found a moisture content of 1.09% moisture. Since the administrative limit for moisture content is 0.9%, the pump was declared inoperable, and the condition was corrected. This event is further discussed in Section 4.3 of this report.

On March 15, 1994, a notification was made to the NRC concerning an unplanned Engineered Safety Feature (ESF) actuation due to a reactor coolant pressure boundary excess flow check valve actuation. While investigating a leak, a plant worker stepped down into the

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[1]The NRC Inspection Procedures used as guidance are listed parenthetically throughout this report.

area of the leak and onto a conduit. At that moment, an instrument line, in close proximity to the conduit, separated from the connection to the excess flow check valve. The connection was apparently loose and already leaking. The excess flow check valve actuates on excessive flow in the respective instrument leg. In this event, the excess flow check valve was on a narrow range variable leg instrument line. The closing of the excess flow check valve caused the level transmitters to sense a false reactor vessel low level condition. This caused an 'A' side half scram and a partial 'A' side NSSSS isolation signal. The reactor vessel low water level scram function of the RPS uses switch contacts from the reactor vessel level instruments. The contacts operate in a one-out-of-two-twice logic when reactor vessel level decreases to Level 3 (+12.5 inches) to initiate a scram. The initiation logic for the NSSSS also uses switch contacts from the reactor vessel level instruments. These contacts operate when reactor vessel level decreases to Level 3 to close all Group 2 isolation valves (residual heat removal (RHR) system valves).

On February 9, 1994, plant personnel made a four-hour report to the NRC regarding various isolations, including the 'B' loop of Unit 1 RHR shutdown cooling, reactor enclosure cooling water, drywell chilled water, and instrument gas systems (NRC Combined Inspection Report Nos. 50-352, 50-353/94-02). During this inspection period, plant personnel determined that the event was not required to be reported and retracted the notification. The isolations occurred during the replacement of a relay in the auxiliary equipment room by Instrumentation and Controls (I&C) technicians. While the isolations were not documented as definitely going to occur, on-duty operations personnel and the I&C technicians clearly recognized the potential for the isolations to occur as a result of preplanned work activities that included a pre-job briefing. Additionally, no other unexpected ESF actuation or other situations occurred that were not recognized by operations personnel during this event. Based on this, the event was determined not to be reportable in accordance with 10 CFR 50.72 (b)(2)(ii). The inspectors were present during the post-critique of this event. At that time, it was clear to the inspectors that the operations staff clearly understood there was a high probability that an isolation could occur, since the relay work was being performed on energized equipment. In fact, operations staff rejected the first maintenance work order for the relay replacement, since it required the removal of a fuse that would have caused the same isolations, including RHR shutdown cooling. Operations instructed the I&C technicians to develop an alternate plan for replacement of the relay (i.e., perform it within the logic energized).

A second four-hour notification was retracted this inspection period. On February 10, 1994, an invalid Unit 1 RPS actuation occurred during the refueling outage with all control rods but one fully inserted (NRC Combined Inspection Report Nos. 50-352/94-02 and 50-353/94-02). The single control rod inserted as a result of the event. The 4 fuel bundles surrounding the control rod were removed and the control rod was withdrawn in accordance with the requirements of Technical Specification 3.9.10. In this specific configuration the RPS actuation was not needed to protect against damage to the fuel barrier since the reactor was fully shutdown and fuel was removed from the control rod cell. There was no safety function associated with the control rod insertion and RPS actuation (the safety function of the RPS was already completed). 10 CFR 50.72 (b) (ii) (B) (2) specifically exempts this from being reported since the actuation was invalid, and occurred after the safety function had already been completed. The inspectors reviewed this event with plant personnel and concluded that the notification was appropriately retracted.

1.3 Unit 2 Recirculation Pump Trip

On February 24, 1994, a licensed operator removed the 'B' phase 4.2 KV line fuse for the 2B motor-generator (M-G) set voltage regulator, reference voltage transformer. The regulator responded by increasing the exciter field voltage to a point where an "Overcurrent Trip/M-G Lockout," occurred causing a trip of the 2B recirculation pump. At the time of the event Unit 2 was operating at 100% of rated power and was subsequently reduced to 35% after the event. Unit 1 was in operational condition 5, Refueling. The operator had intended to remove the fuse from the Unit 1, 1B M-G set, which was out of service for refueling outage work, and deenergized under a tagging clearance. The operator realized he was on the wrong unit when he noticed an arc as he was removing the 4.2 KV fuse and immediately replaced the fuse. He then notified the main control room that he had partially removed the fuse from the 2B M-G set. Following the reduction of Unit 2 power to 35% of rated per procedure, the 2B recirculation pump was restarted without incident. This event was further reviewed during a Special Team Inspection (50-352/94-09 and 50-353/94-09).

1.4 Drywell Closeout Inspection

Near the end of the Unit 1 refueling outage, a drywell close-out inspection was conducted as required by procedure GP-2 Appendix 2, Drywell/Suppression Pool Closeout and Inspections, and ST-0-RRR-900-1, Drywell Close-out Inspection. The inspectors accompanied a radwaste supervisor and a senior licensed operator on the inspection, on March 9, 1994. The inspection lasted for over 2 hours and was very detailed. However, a number of deficiencies were identified, requiring followup actions. Many of the deficiencies were immediately corrected, and a large amount of extraneous material was removed from the drywell. The results of the inspection were therefore documented as unsatisfactory. The deficiencies were corrected, and the procedure was performed again on March 10, 1994, with the plant manager involved.

The inspectors concluded that the overall process to ensure that the drywell was properly closed out was very good. When a large number of deficiencies were identified, the inspection procedure was appropriately performed again, and good management involvement was noted. Although the inspectors were concerned with the large number of deficiencies initially identified, the inspectors concluded that the Unit 1 drywell was closed out properly, and that the inspection conducted was very thorough and complete.

1.5 Resumption of Shoreham Fuel Shipments

On March 26, 1994, the resumption of receipt of Shoreham fuel shipments began with the arrival of shipment number 20, of the total 33 shipments. The inspectors observed the arrival and entry of the shipment into the protected area at Limerick Generating Station. Health physics personnel properly frisked the container, and security properly controlled entry of the shipment into the protected area. Additionally, good management oversite was exhibited for the first shipment to be received after the Unit 1 refueling outage. The remaining shipments are scheduled to be received over the next two months.

1.6 Housekeeping

During the Unit 1 refueling outage, a large number of activities were conducted in the RHR pump rooms. Both RHR heat exchangers were replaced, and various service water isolation valves were added for component isolation capability. The inspectors regularly toured these areas to observe activities in progress and control of cleanup after completion of work and during system restoration. Throughout system restoration and plant startup activities, the rooms were found with a large number of transient materials present that are not normally present during plant operation. Some of the materials, such as tools, scaffolding and insulation, were present due to the continuation of some of the work, including insulating the heat exchangers. However, the inspectors found a significant amount of loose material, such as bolts, pipe caps, chains, tubing, extension cords, and wood. This material should have been removed after completion of activities in these areas. The inspectors were concerned that some of these objects, on the upper elevation, could potentially fall through the floor grating onto personnel or equipment, and cause damage. These concerns were brought to the attention of plant management.

On March 23, 1994, the Limerick plant staff conducted a comprehensive plantwide cleanup effort. This is a planned quarterly activity, which in this case coincided well with the completion of the Unit 1 refueling outage. The intent was to return the plant to pre-outage levels of cleanliness. Portions of the all-day effort were observed by the inspectors. Additionally, the inspectors reviewed plant conditions on the day after the cleanup. The cleanup was successful in returning the plant to an excellent condition as was observed prior to the outage.

The inspectors concluded that, prior to and after the outage, plant conditions were excellent. During the Unit 1 outage, conditions in Unit 2 were also observed to be excellent. However, in one instance, control of housekeeping conditions in Unit 1 during the outage was deficient. In both Unit 1 RHR pump rooms the housekeeping conditions were not returned to a good level, after completion of activities in these areas.

2.0 MAINTENANCE (62702, 62703)

2.1 Maintenance Observations

The inspectors reviewed the following safety-related maintenance activities to verify that repairs were made in accordance with approved procedures and in compliance with NRC regulations and recognized codes and standards. The inspectors also verified that the replacement parts and quality control used on the repairs were in compliance with PECO Energy's Quality Assurance (QA) program.

The following maintenance activities were reviewed:

- emergency diesel generator D24 coolant leak

This leak was initially discussed in NRC Combined Inspection Report 50-352,353/94-02. The inspectors followed the corrective actions taken, and observed that the leak rate had decreased notably prior to the performance of the corrective maintenance. The leak repair was properly planned, scheduled and fixed, with verification that no further leakage was evident.

- excess flow check valve instrument line repair

This instrument line connection fitting failure resulted in an ESF (Section 1.2). The connection repair was found to be properly planned and completed by I&C technicians.

2.2 Control of Troubleshooting

During this inspection period, the inspectors reviewed the control of troubleshooting activities as part of Region I Temporary Instruction 94-01. At Limerick, the administrative requirements, controls, and responsibilities for performing troubleshooting are contained in administrative procedure A-41.1, Troubleshooting Plant Equipment, Revision 13. This procedure was developed in 1986 in response to a plant trip while personnel were taking electro-hydraulic control (EHC) system readings. Twenty four reference documents are listed, including various event reports, quality concerns, and other NRC and industry documents. The inspectors reviewed the procedure and discussed troubleshooting with plant personnel. The Scope of A-41.1 states that the procedure is required when making changes in system configurations to perform troubleshooting activities on safety-related and nonsafety-related equipment. The procedure does not cover work that is performed under a work order, such as relay replacement or major disassembly of devices.

Operations, maintenance, I&C, and engineering personnel can perform troubleshooting activities using A-41.1; however, complex troubleshooting is normally conducted by the appropriate system manager (engineer). The system manager has the lead responsibility, and a list of the appropriate system managers is located in the index. Troubleshooting is controlled, approved and documented on the LGS Troubleshooting Control Form (TCF), which is exhibit A-41.1-1. The stand alone form documents the problem, step-by-step troubleshooting method (which establishes work boundaries), impact on operations, special conditions required, and restoration instructions. Reference documents may be identified on the TCF, but are not required. The approvals section of the TCF documents whether or not a 50.59 determination is needed and if an independent verification is required. The form receives a technical review from the work group supervisor, who must be a station qualified reviewer, and is authorized by the operations shift supervisor, who reviews the activity for plant impact. The TCF documents a description of the system configuration change (including lifted leads and jumpers), along with the as-found and as-left conditions. Finally, the results and post-TCF testing are documented. If the scope changes and is outside of the initial scope of the troubleshooting, the TCF is revised or a new one is initiated. Separate work packages are required for corrective maintenance, which could be performed concurrently with troubleshooting, but this is not likely. Parts are normally removed and controlled by work orders, but if a component such as a fuse is replaced during troubleshooting, the old fuse is retained for failure analysis.

The inspectors reviewed several active TCFs, and found them properly filled out, approved and tracked. The inspectors concluded that troubleshooting activities are well controlled. Only one instance in the past 2 years was found where personnel did not properly use the TCF as required, which resulted in a violation (NRC Combined Inspection Report 50-352, 353/93-14).

2.3 Recirculation Pump Discharge Valve F031A Leak Repair

The 1A reactor recirculation pump discharge isolation valve, HV-043-1F031A was inspected during the Unit 1 refueling outage (1R05), for excessive packing leakage. The inspection was conducted at 500 psi during the unit depressurization, and there was no sign of leakage at that time. The leakage problem was suspected based on leakage discovered on Unit 2 during its previous outage (Unit 2 currently has HV-043-2F031A electrically back seated, which corrected the leakage problem). Several weeks following the shutdown of Unit 1 an auxiliary operator (AO) noted excessive packing leakage while he was performing a filling and venting operation of the recirculation pump loop and seal. The AO initiated a corrective maintenance action request to have the valve repacked; two rings of packing were replaced. The leakage was still apparent during the prestart 1000 psi hydrostatic test. Approximately 1 pint/minute was observed with the valve open, on the back seat, and in the shut position. Following this, the maintenance action was converted to a NCR. The NCR was dispositioned to inject the valve packing with sealant.

The valve is a stainless steel, 28 inch motor operated valve, with manual override. When starting a recirculation pump, the discharge valve must be closed. The discharge valve must be fully opened within 3 minutes after pump start or the pump will trip. If, at any time after this 3 minute interval, the discharge valve goes less than 90% open, the pump will instantly trip. Following a recirculation pump trip, the affected pump will coast down in speed and then reverse direction due to reverse flow induced by the other operating pump. In order to avoid bearing wear from low speed rotation, the discharge valve on the tripped pump should be shut for 5 minutes. This is a sufficient period of time to allow the pump to settle on its bearings and prevent flow induced pump rotation when the discharge valve is opened. Thermal or pressure binding of the discharge valve may occur if the valve is closed while the system is hot and significant cooldown occurs. Therefore, the valve is reopened to prevent such binding. The valve serves no operational safety function. In fact, a nonconformance report (NCR) is currently written to eliminate the valve from the Q list, UFSAR, and technical specifications.

The inspectors reviewed the NCR and the maintenance work order C0151663 for this repair. The inspectors then discussed the planned work with site engineering, maintenance, and the vendor representatives. Additionally, the 10 CFR 50.59 evaluation was reviewed and the inspectors agreed with PECO Energy's conclusion that a 50.59 safety evaluation was not required.

The sealant material selected for this application was Valve Pack Ax. The vendor stated that this sealant had recently been used at other facilities including Oyster Creek, TMI, and Salem in similar applications, and the valves were verified to be capable of stroking following the injection. The vendor told PECO Energy that the injection of leak repair sealant will have an insignificant effect on the packing load and the valves ability to stroke. In a letter to PECO Energy, the vendor stated that the lubricants contained in the formulations insure the proper functioning of the valve stem and prevents injected valve packing compounds from becoming a rigid mass. The coefficient of friction of the valve packing material is expected to be similar to that of conventional packing material. This information was based on vendor experience, not testing. PECO Energy also stated they had never experienced a problem with post injection valve operations at Limerick. PORC requested further information concerning post repair valve operation, from site engineering, following a presentation of the NCR disposition to use leak sealant to repair the valve. In response, VOTES testing was performed and the data showed approximately 50,000 lbs. of thrust during the seating evolution and about 1000 lbs. thrust running torque. It appears the difference will be sufficient torque to overcome the additional friction on the stem from the leak sealant. These were the bases PECO Energy used to determine that post sealant valve cycling was not needed.

Chemical analysis was performed as part of the process to put this sealant material on PECO Energy's approved materials list. PECO Energy stated the vendor informed them that the material was not adversely effected by radiation or thermal transients, and the seal would last two years; if the valve was stoked more often than every six months, it would probably not hold. The NCR gives maintenance the leeway to perform an additional injection subsequent to the first injection without notifying engineering again.

In order to install the injection valve, a hole was drilled in the intermediate gland; no pressure boundary part was affected. The valve packing assembly consists of an upper, intermediate and lower gland packing. PECO Energy did not require any quality verification because the attached temporary valve is not a Q component. The only requirement was 7 threads minimum engagement. The intermediate gland is made of cast stainless steel, ASTM SA-351; the temporary valve was required to be of compatible material per site engineering.

On March 9, 1994, the inspectors witnessed the leak seal application on the valve. The recirculation pump was running and the valve was electrically opened and not on its back seat. The inspectors observed approximately a 2 gpm leak from the valve gland. The actual injection activity was well controlled with good use of the ALARA concept. Two teams were used for the activity. One group was responsible for manually back seating the valve, and one group, including the vendor, performed the injection. With the valve back seated, leakage slowed to a small steady drip. The vendor injected the sealant with a "grease-gun," type tool and the leakage stopped (pressure behind the packing was only pump discharge pressure with the vessel at atmospheric pressure). The amount of sealant injected could not be measured at the time of the injection process. The vendor technician used a pressure gauge and the "feel of the grease gun" to determine when the proper amount was injected. This coincided with the stopping of coolant leakage. Later, the remaining sealant in the injection device was measured and it was determined that 5 cubic inches of sealant was injected.

Subsequent to the Unit 1 startup, at approximately 1000 psi vessel pressure with the recirculation pump at minimum speed, a drywell inspection was performed. The leakage at that time had increased to about a pint/minute with a steam and water mixture spraying about 5 inches out of the upper gland area. Prior to the unit startup, the I&C group had installed a video camera in the drywell adjacent to the discharge valve. The camera provided a clear, sharp picture of the valve. In accordance with the NCR disposition, a second injection was performed, and approximately 4 cubic inches of sealant was injected. The second injection reduced the leakage to 50-80 drips/minute with no visible steam or water spray. Four days later, with the unit at 100% of rated power (March 15, 1993), the leakage increased to a stream (1-2 foot high) of water and steam, close to the valve stem, coming from the upper gland. By the end of the inspection period the stream was reduced to about 5 inches high, and what is believed to be sealant material, could be seen on the lower gland follower. The system manager and/or maintenance personnel are continuing to observe the valve daily, via the drywell camera.

The valve leakage is currently being considered unidentified reactor coolant system leakage. For Unit 1, this leak rate has been a fairly constant 0.4 gpm since startup. In order to ensure that the operators are familiar with the condition of the discharge valve, a Shift Training Bulletin was issued regarding the valve leakage and response to a 1A recirculation pump trip. Additionally, a note was placed in the Shift Night Orders that states that if unidentified leakage should increase to 1 gpm, notify plant management and immediately check the video camera to monitor for any change in leakage. The technical specification limit (3.4.3.2) for unidentified reactor coolant system leakage is 5 gpm. The current plan, if an increase in leakage to 1 gpm occurs, calls for a power reduction to 10% of rated, de-inerting the drywell and injecting a more rigid sealant material called Quick Fix. Additionally, a number of other contingency plans are being reviewed and evaluated by plant management. The inspectors are continuing to monitor the valve leakage via the camera, and are tracking the unidentified coolant leakage as part of the normal inspection program. Overall, the repair activities for the HV-043-1F031A valve have been well planned and implemented in accordance with plant procedures.

3.0 SURVEILLANCE (61726)

3.1 Surveillance Observations

During this inspection period, the inspectors reviewed in-progress surveillance testing and completed surveillance packages. The inspectors verified that the surveillances were completed according to PECO Energy approved procedures and plant technical specification requirements. The inspectors also verified that the instruments used were within calibration tolerance and that qualified technicians performed the surveillances.

The following surveillances were reviewed:

- GP-10, Operational Hydrostatic Test, Revision 16
- ST-3-107-790-1, Control Rod Scram Timing, Revision 18

These surveillances were conducted during Unit 1's startup from the refueling outage. The inspectors observed portions of the surveillances in the main control room, and out at the appropriate equipment. For both of the surveillances, the inspectors observed good performance by operations personnel, with good management oversight.

4.0 ENGINEERING (71707)

4.1 Jet Pump Beam Replacement and In-Vessel Visual Inspection

The inspectors viewed videotapes of the jet pump beam replacement and in-vessel visual inspection activities that occurred during the 1R05 refueling outage.

Initially, an as-found inspection of the jet pump set screws was performed to ensure that detensioning of the hold down beams would not disturb the jet pumps. All 20 new beams were installed and inspected via camera and television monitor. The retainers at the top of the inlet mixers were spread to release the old beams. Each retainer was inspected to determine if the deformation caused any cracking, and no indications were found. They will remain spread and will be inspected in future outages. A visual inspection was done on the old jet pump hold down beams. No cracking was found in any of the beams. No further examination is planned. The beams are currently being stored to be disposed of as high level radwaste.

The in-vessel visual examination is part of the 10 year inservice inspection (ISI) program. All vessel interior areas and internal components that are accessible are examined every other outage. The examinations are performed in accordance with the 1980 Edition of the ASME Boiler and Pressure Vessel Code, Section XI, 1986 Edition. No recordable indications were found during the inspection. Therefore, most of the tape showed the discerning of a 1 mil qualification standard that ensured sufficient lighting and water clarity. The area around the low pressure coolant injection (LPCI) system coupling was videotaped as input in determining a more efficient hydrolyzing technique for future outages. This area is a trap for corrosion products and future hydrolyzing efforts may include a different nozzle or a higher pressure.

The videotapes were an effective tool for reviewing the results of the jet pump beam modification. Both this modification and the in-vessel visual inspections were conducted according to procedure, safely, and efficiently.

4.2 RHR Discharge Pressure Increases

Shortly after the Unit 1 return to power operations, after the 1R05 refueling outage, the inspectors noted in the control room logs that operators were frequently depressurizing the 'B' RHR discharge header. This activity was occurring every 3-4 hours. The control room annunciator alarm setpoint is 400 psig, with an alarm response procedure that directs the operator to bump open the RHR full flow test valve to relieve pressure to the suppression pool. The alarm response procedure also cautions the operator that if the alarm reoccurs immediately after relieving pressure, then leakage rate past isolation valves may be greater then 1.0 gpm, a technical specification limit.

The inspectors were aware of a similar condition on Unit 1 prior to the outage where the operators were required to depressurize 'B' RHR header approximately twice a day. This condition also exists on Unit 2 'B' RHR, with the same frequency of depressurization. One of the identified causes of the Unit 2 'B' RHR pressurization and Unit 1, prior to the outage, was leakage past the HPCI steam isolation valve to the 'B' RHR heat exchanger. HPCI steam is supplied to the heat exchanger during the Steam Condensing Mode of RHR. During the Unit 1 outage (1R05), the Steam Condensing Mode was removed from service and was expected to correct the pressurization problem in the 'B' loop of RHR. Since the problem still existed after Unit 1 was restarted, the inspectors questioned the source of the inleakage.

The inspectors contacted the system manager for RHR. The system manager was already aware of the problem and was in the process of determining the source of the system inleakage. Based on the depressurization rate and a known quantity of water drained from the 'B' RHR discharge header, the inleakage from the discharge piping isolation valves was calculated to be 0.89 gallons per hour. At the end of the inspection period the frequency for depressurizing Unit 1 'B' RHR header had gone from every 4 hours to every 8 hours, indicating a decrease in the leakage rate. The system manager has also reviewed the local leakrate test (LLRT) for the 'B' loop RHR isolation valve (performed during the outage) and verified that it was well within the established limits. The inspectors, as well as the plant staff, will continue to monitor this inleakage for any signs of an increase.

4.3 HPCI Oil Moisture Content

An unacceptable moisture content was discovered in the Unit 1 HPCI pump oil reservoir on March 12, 1994, (Section 1.2). After identification, the pump was removed from service, the oil was drained, and replaced with new oil. Sampling of the new oil on March 13, 1994, showed a moisture content of 0.47%. This value is higher than desired (approximately 0.1%), so the oil was filtered until a 0.05% value was obtained. The 0.47% value was suspected to be due to inadequate cleaning and flushing of the system prior to addition of the new oil. At the end of the inspection period, sampling of the oil had been increased from quarterly to weekly to confirm that no inleakage of water was occurring; no problems were noted after two weeks of sampling.

The HPCI system manager suspected that the original inleakage of water (approximately 1.5 gallons) was due to water not adequately removed from the barometric condenser on March 9, 1994. Apparently, the pump discharge valve was not opened enough, which caused the water in the barometric condenser to back up into the turbine and run down into the oil sump through the bearings. Subsequent to returning the HPCI system to an operable status, the system manager evaluated the type of oil being used to determine if the 0.9% administrative limit is too restrictive. The 0.9% limit was based on engineering judgement to provide sufficient margin from a 1.3% water content that contributed to a failure of the HPCI system, at another site, due to a degraded electronic governor remote (EGR).

The inspectors reviewed a report from the system manager, which concluded that for the occurrence on March 12, 1994, the HPCI system was not inoperable due to the measured water content in the oil. This conclusion was based on the short time the oil was in the pump; the oil was newly replaced during the Unit 1 refueling outage. There was an inadequate amount of time for sludge to form, oxidation to take place or corrosion to occur, which would have had a damaging effect. Additionally, an oil, superior to that used for the case of the failed EGR, was being used. Finally, satisfactory startup test results showed proper operation of the control and lube oil systems, between March 9 and 12, 1994. At the close of the inspection period, the guidance relayed to the inspectors instructed that the HPCI system would not necessarily be declared inoperable based only on a moisture content greater than 0.9%. Other factors would have to be evaluated such as evidence of sludge in the oil. However, a moisture content of approximately 0.5% or greater would result in actions to lower the moisture content, as soon as practical, by filtering.

The inspectors concluded that the system manager was very knowledgeable of the system and was appropriately involved in the corrective actions taken. Additionally, the current guidance being followed appears to be appropriate to ensure continued HPCI system availability.

5.0 PLANT SUPPORT (71707)

5.1 Radiological Protection

During the inspection period, the inspectors examined work in progress in both units including health physics (HP) procedures and controls, ALARA implementation, dosimetry and badging, protective clothing use, adherence to radiation work permit (RWP) requirements, radiation surveys, radiation protection instrument use, and handling of potentially contaminated equipment and materials.

The inspectors observed individuals generally frisking in accordance with HP procedures. A sampling of high radiation area doors was verified to be locked as required. Compliance with RWP requirements was reviewed during plant tours. RWP line entries were reviewed to verify that personnel provided the required information and people working in RWP areas were observed as meeting the applicable requirements.

5.2 Security

Selected aspects of plant physical security were reviewed during regular and backshift hours, to verify that controls were in accordance with the security plan and approved procedures. This review included the following security measures: guard staffing, vital and protected area barrier integrity, and implementation of access controls including authorization, badging, escorting, and searches. The inspectors did not identify any deficiencies, and concluded that observed activities were properly conducted with good management involvement.

6.0 REVIEW OF LICENSEE EVENT AND ROUTINE REPORTS (90712, 90713)

6.1 Licensee Event Reports (LERs)

The inspectors routinely reviewed LERs and performed followup inspections to PECO Energy's actions regarding the disposition of corrective initiatives. The inspectors reviewed the following LERs and found that the events were described accurately, PECO Energy had identified the root causes, implemented appropriate corrective actions and made the required notifications.

LER 1-94-003, Residual Heat Removal Service Water system erroneously shutdown while supporting decay heat removal, Event Date: February 6, 1994, Report Date: March 8, 1994.

This event is discussed in NRC Combined Inspection Report 50-352, 353/94-02.

LER 1-94-004, LER concerning an event where a Primary Containment Isolation Valve inadvertently isolated, an ESF, causing a loss of RHR shutdown cooling due to personnel error, Event Date: February 12, 1994, Report Date: March 14, 1994.

This event is discussed in NRC Combined Inspection Report 50-352, 353/94-02.

The inspectors found that the LERs listed above met the requirements of 10 CFR 50.73 and had no further questions regarding these events.

6.2 Routine Reports

Routine reports submitted by PECO Energy were reviewed to verify the reported information. The following report was reviewed and satisfied the requirements for which it was reported.

Station Monthly Operating Report for February, dated March 14, 1994.

7.0 FOLLOWUP OF PREVIOUS INSPECTION FINDINGS (92701, 92702)

(Closed) Unresolved Item (50-353, 353/92-19-01). Backup diesel fire pump fuel consumption.

This item was considered unresolved pending resolution of the actual fuel consumption of the backup fire diesel pump. The inspector was concerned that the actual consumption rate had not been verified by testing. Therefore, for sustained operation, operators did not have good guidance for ordering fuel.

The inspectors discussed the issue with fire protection personnel, and reviewed the appropriate Shift Update Notice (SUN) in the main control room. The SUN instructs operations personnel to order fuel before the tank is 1/2 full, during sustained operations. Additionally, a notice was placed on the fuel tank as a reminder to operations personnel. The inspectors had no further concerns, and this unresolved item is closed.

(Closed) Unresolved Item (50-353/92-27-03). RCIC vacuum breaker check valve temperature switch.

The subject temperature switch is in the turbine exhaust vacuum breaker line whose design function is to provide an alarm in the main control room resulting from steam leakage past the vacuum breakers. While the temperature switch setpoint is 225°F, it was not clear from a review of the RCIC surveillance test data what the actual temperature of the steam in the exhaust line is during operation. It appeared that the steam temperature was very close to the 225°F setpoint, thereby, raising the question whether the switch would actually alarm in the event the check valves leaked. The inspector requested PECO Energy to supply the engineering setpoint calculation that would provide the basis for 225°F. The inspector was informed that there was no specific calculation available and the setpoint was based on the engineering judgment of the design engineer. As a result of this review, the system engineer planned to take additional test data, using more accurate instrumentation, to determine actual steam exhaust temperature. The question of the adequacy of the temperature switch setpoint was unresolved pending the completion of this additional testing and data evaluation.

On December 16, 1992, during a Unit 2 RCIC test run RCIC steam exhaust temperatures were recorded. The instrument used was a surface temperature pyrometer. The temperature was measured at three locations.

- HV-049-2F060 valve yoke and stem - 213°F.
- Between vacuum breakers and HV-049-2F080 - 213°F.
- Immediately downstream of the vacuum breakers - 83°F.

On January 11, 1993, an instrument setpoint change request (ISCR) was generated to reduce the setpoint from 225°F to 200°F for both the Unit 1 & 2 RCIC systems. This change was completed on both units in April 1993.

Additionally, in light of the changes made to the setpoint in the RCIC system, the HPCI system was evaluated for the same concern, since that system also had a setpoint of 225°F. In May 1993, temperature data was collected during a HPCI run on Unit 1.

- Exhaust line at HV-055-1F072 - 239°F.
- Outboard Vacuum Breaker PCIV HV-055-1F093 - 208°F.
- Inboard Vacuum Breaker PCIV HV-055-1F-95 - 110°F.

Based on this data a setpoint change was recommended to 210°F. This setpoint would be more sensitive to steam flow and not likely to alarm spuriously. The action was completed on both HPCI systems in November 1993. The inspectors had no further questions concerning this issue and consider the review of the HPCI setpoint an indication of a proactive engineering group. This unresolved item is closed.

8.0 MANAGEMENT MEETINGS

8.1 Exit Interviews

The inspectors discussed the issues in this report with PECO Energy representatives throughout the inspection period, and summarized the findings at an exit meeting with the Senior Manager Operations, Mr. L. Hopkins, on March 29, 1994. PECO Energy personnel did not express any disagreement with the inspection findings. No written inspection material was provided to licensee representatives during the inspection period.

8.2 Additional NRC Inspections this Period

Three Region-based inspections were conducted during this inspection period. Inspection results were discussed with senior plant management at the conclusion of the inspections.

Date	Subject	Inspection No.	Lead Inspector
03/05/94	Inservice Inspection	50-352/94-05 50-352/94-05	C. Beardslee
03/15/94	Team Inspection	50-352/94-09 50-353/94-09	W. Schmidt
03/24/94	Environmental Monitoring	50-352/94-10 50-353/94-10	L. Peluso