UNITED STATES NUCLEAR REGULATORY COMMISSION

REGION I

Inspection Report Nos.	50-387/95-08; 50-388/95-08
License Nos.	NPF-14; NPF-22
Licensee:	Pennsylvania Power and Light Company 2 North Ninth Street Allentown, Pennsylvania 18101
Facility Name:	Susquehanna Steam Electric Station
Inspection At:	Salem Township, Pennsylvania
Inspection Conducted:	March 28, 1995 - May 15, 1995
Inspectors:	M. Banerjee, Senior Resident Inspector, SSES B. McDermott, Resident Inspector, SSES J. Laughlin, Emergency Preparedness Specialist, DRSS D. Mannai, Resident Inspector
Approved By:	J. White, Chief, Reactor Projects Section No. 2A, — Date 6/15/95

Scope: Resident Inspector safety inspections were performed in the areas of plant operations; maintenance and surveillance; engineering; and plant support. Initiatives selected for inspection were plant management walkdowns.

Findings: Performance during this inspection period is summarized in the Executive Summary. Details are provided in the full inspection report.

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EXECUTIVE SUMMARY

Susquehanna Inspection Reports
50-387/95-08; 50-388/95-08
March 28, 1995 - May 15, 1995

Operations

The first forty five day refueling outage for Unit 1 was conducted in a safe manner. Activities observed on the refueling floor were performed in a well controlled and deliberate manner with conservative decision making to address the problems encountered. Good management attention and supervision of the refueling floor activities were also observed.

The Unit 1 suppression pool diver's inspection during the outage demonstrated the licensee's continued commitment to ensuring the potential for ECCS strainer clogging is minimized at Susquehanna. The potential operability effects of a sheet of visqueen on RCIC pump operability remains unresolved pending further review by the licensee and evaluation by NRC.

The licensee's immediate actions in response to the Unit 1 generator seal oil spill event were good. The inspector considered human factors associated with the valve position indication and the oil filter's vent design to be among the major causes of this event. The event's safety impact was low due to having nitrogen in the generator (for a pressure test) as opposed to hydrogen used during operation. However, the event was important because it highlighted the potential for a significant event upon loss of generator seal oil at power. An Event Review Team was tasked with reviewing this event and, based on an assessment of their progress to date, the inspectors determined that all relevant safety considerations are being addressed.

Control room operators appropriately responded to an April 15 Unit 2 scram on load reject and all plant safety systems functioned as designed. The inspectors noted that since 1983 sixteen scrams at SSES have been caused by problems associated with the switchyard or turbine generator. The licensee is in the process of implementing broad corrective actions that are aimed at improving the performance of switchyard maintenance for both units. Issues developed during their investigation of this event and during a review of the past events were compared and combined to provide assurance of adequate corrective actions.

Maintenance/Surveillance

The control rod drive mechanism changeout during the outage was well controlled and monitored with good support from the system engineer and health physics technicians.

The licensee's first under water installation of main steam line plugs was performed in a controlled and deliberate manner. Additional experience with the installation tool is expected to reduce the installation time and consequently personnel exposure. The skill of the personnel handling the rigid pole system was noted as very good.

During performance of an 18 month surveillance for loss of offsite power, the licensee had to abort the first start attempt due to a personnel error in starting the diesel generator data recorder. The second attempt was better coordinated and the inspector observed good command and control during the remainder of the test.

The Unit 1 RCIC turbine overspeed trip test was observed and two human performance errors were identified. A plant operator reset the thermal overloads for the wrong breaker and a rubber water hose used during the test was hung on an uninsulated auxiliary steam pipe. Although the potential existed, no safety consequences resulted from these errors.

Engineering/Technical Support

The licensee properly identified the root causes of the Unit 2 load reject and is pursuing broad corrective actions to prevent future events of this nature. System Engineering and the Relay and Test division are currently working on corrective actions aimed at improving communication, procedures, work practices, drawings, and staffing, associated with the SSES switchyards.

Uninterruptible power supply (UPS) 2D240 was returned to service on January 30, 1995 with an inoperable battery and was not aligned to the alternate supply as described in Final Safety Analysis Report Section 8.3.1.8. On April 15th, the UPS did not transfer to its alternate supply when required and isolated the distribution panel. The UPS was therefore inoperable without its battery. The UPS failure resulted in an unnecessary complication for the control room operators during the scram recovery, causing anomalous indications and system responses. Operator action was necessary to restore power to the affected instrumentation. If the UPS had been aligned as described in the FSAR, the April 15th voltage dip would not have caused isolation of the instrument AC distribution panels.

Plant Support

The inspector concluded that good health physics support of the TIP detector replacement work was effective in minimizing the radiation workers' dose. The licensee's refueling outage in-progress ALARA review was noted to have helped the licensee in achieving their refueling outage exposure goal of 200 man-rem.

The licensee's changes contained in Revision 21 of the Emergency Plan and its associated Implementing Procedures were acceptable, with one change still under review. PP&L plans to discontinue mailing emergency instruction brochures to local residents and commercial facilities. This information will still be published in local telephone directories.

Safety Assessment/Quality Verification

The licensee's response to one past violation and two unresolved items were reviewed and supported closure of the issues. One unresolved item was updated during this inspection period.

Management support and direction for thorough corrective actions in response to events during this period were considered a strength. Examples include the establishment of an ERT for the seal oil event and support for broad corrective actions in response to the Unit 2 switchyard problems.

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DETAILS

1. SUMMARY OF FACILITY ACTIVITIES

Susquehanna Unit 1 Summary

At the start of this inspection period Unit 1 was in cold shutdown and in day four of the unit's eighth refueling outage. The licensee officially ended their refueling outage on May 7th with synchronization of the Unit 1 main generator to the grid. The refueling outage lasted forty three days, finishing two days ahead of schedule. Power ascension following the outage was delayed due to maintenance problems with the 'C' reactor feed pump seals. At the end of this inspection period, the unit was in operational condition 1 at 80% of rated thermal power.

Susquehanna Unit 2 Summary

Unit 2 began this inspection period at 100% power. Power reductions were made during the period to allow for turbine valve testing and control rod pattern adjustments. On April 15th, Unit 2 scrammed from 100% power due to a load reject that occurred when operators attempted to open a main generator output breaker in support of planned maintenance. The second generator output breaker opened simultaneously with operation of the intended breaker due to a misconfigured generator protective circuit in the 500 kV switchyard. All plant safety systems responded as expected to the transient. An anomalous response from 2D240 uninterruptible power supply caused a loss of some controls, indications, and other components. After completing the scheduled forced outage work, Unit 2 was returned to 100% power on April 23rd.

2. PLANT OPERATIONS (71707, 92901, 93702, 40500)

2.1 Plant Operations Review

The inspectors observed the conduct of plant operations and independently verified that the licensee operated the plant safely and according to station procedures and regulatory requirements. The inspectors conducted regular tours of the following plant areas:

- Control Room
- Control Structure
- Unit 1 and 2 Reactor Buildings
- Unit 1 and 2 Turbine Buildings
- Emergency Diesel Generator Bays
- Protected Area Perimeter
- Security Facilities
- Radwaste Building

Control room indications and plant systems were independently observed by NRC inspectors to verify plant conditions were in compliance with station operating procedures and Technical Specifications (TS). Alarms received in the control room were reviewed and discussed with operators; operators were cognizant of control board and plant conditions. Control room and shift manning were in accordance with TS requirements.

During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication of equipment status. These records included various operating logs, turnover sheets, blocking permits, and bypass logs. The inspector observed plant housekeeping controls including control and storage of flammable material and other potential safety hazards. Posting and control of radiation, high radiation, and contamination areas were appropriate. Workers complied with radiation work permits and appropriately used required personnel monitoring devices.

The inspectors performed 36.3 hours of backshift and deep backshift inspections during the period. The deep backshift inspections covered licensee activities between 10:00 p.m. and 6:00 a.m. on weekdays, weekends, and holidays.

2.2 Unit 1 Fuel Shuffle

On April 14 and 20, 1995, the inspector observed fuel movement. During this refueling outage, fuel assemblies were moved between core locations rather than being offloaded to the fuel pool and reloaded. This fuel "shuffle" reduced the total number of fuel moves, decreased the necessary vertical movement of the refuel bridge mast, and helped to shorten the refueling outage duration.

The inspector noted good proficiency of the reactor operator and the senior reactor operators involved in the move movements. The operators strictly followed the fuel movement instruction sheet (FACCTAS) and procedures OP-ORF-005, Rev 2, Refueling Operations, and OP-181-001, Rev 14, Refueling Platform Operation. Good command and control, continuous communication with the control room operator, and management presence were observed. During the fuel shuffle, operators identified a FACCTAS error related to the grapple orientation for moving single blade guides. All fuel movement was stopped pending reactor engineering's review and resolution of the issue. A condition report was written document the incident and track further review.

The inspector concluded the refueling operation was executed in a well controlled and deliberate manner with good management oversight and appropriate consideration of safety issues.

2.3 Supplemental Decay Heat Removal System Operation

The Susquehanna Steam Electric Station Final Safety Analysis Report (FSAR), Section 9.1.3.3, states that at normal design conditions the fuel pool cooling and cleanup system will maintain the fuel pool water less than 125°F. The fuel pool cooling system heat exchangers are normally supplied by the service water (SW) system. During emergency heat load conditions (with a full core offload to the pool), the RHR system fuel pool cooling assist mode operation can be used to maintain pool temperature below 125°F. Also, the FSAR requires that the fuel pool cooling be maintained during the outage such that the calculated time for pool boiling is greater than 25 hours. To provide additional margin, the licensee administratively limits the maximum fuel pool temperature to 115°F.

To provide the required heat removal capacity during shutdown of the service water and RHR systems early in the outage, a supplemental decay heat removal (SDHR) system was temporarily installed to provide cooling for the fuel pool heat exchangers. NRC Inspection Report 50-387/95-01 contains a design review of this system. The SDHR is an open loop cooling system which draws water from, and returns it to, the trailer mounted forced draft cooling towers parked outside the reactor building. Additionally, because the fuel pools of both units were cross tied, the Unit 2 fuel pool cooling system was also available to cool the Unit 1 pool and reactor cavity (when the refueling gates were removed). A radiation monitor was installed on the SDHR system discharge path to the temporary cooling towers comparable to TS required monitoring of the SW discharge. The licensee ran tests to ensure adequate SDHR flow and a 5 psi differential pressure existed across the fuel pool heat exchangers to reduce the potential for leakage of radioactive materials into the open loop SDHR system. The control room operators regularly monitored the fuel pool temperature. The shift technical advisors (STAs) and system engineer calculated heat up rates daily to ensure the FSAR requirement for 25 hours to reach boiling was not exceeded.

The inspector reviewed the performance of the SDHR system by monitoring fuel pool temperature and configuration, and via discussions with the STAs, system engineer, control room operators, and the SDHR equipment operators. The inspector noted that the licensee issued an internal correspondence (hot box 95-026) to formalize the chain of communication between the control room, vendor personnel at the SDHR system trailer and the nuclear systems engineers serving as Test Directors for the temporary system. The inspector confirmed that the appropriate TS Action Statements were met when SDHR system was lost or when the radiation monitor was inoperable. On April 6, 1995, the SDHR system was shut down for a short duration and the maximum fuel pool temperature did not exceed 97°F.

The inspector concluded the licensee maintained adequate cooling of the spent fuel pool and reactor cavity during the Unit 1 refueling outage and was in consistent with the FSAR commitments. The system engineers and the STAs provided good oversight of SDHR operation.

2.4 Unit 2 Scram on Load Reject

On April 15, 1995 at 9:06 a.m., the Unit 2 reactor scrammed due to a generator load reject that occurred when the 500 kV switchyard south bus circuit breaker (CB) 3T was opened in preparation for planned maintenance. A four hour notification was made to the NRC due to the unplanned actuation of an emergency safety feature, i.e., the reactor protection system (RPS) trip. The root cause of the load reject and licensee's analysis is discussed in Section 4.1 of this report.

The generator load reject resulted in a turbine trip and turbine control valve fast closure. The safety system response to the scram was as expected and the operators implemented the scram procedure. All of the control rods inserted within the technical specification required time. One rod was noted to exceed the licensee's administrative limit for stroke time to notch 45 by an insignificant amount. The end-of-life reactor protection system trip of the recirculation pumps was in effect, and tripped both recirculation pumps. This trip counteracts the void reactivity feedback due to pressurization following turbine trip and fast closure of the turbine control valves. Reactor pressure

increased to 1117 psig due to control valve closure, and vessel level dropped to a minimum of 4.5 inches for a few seconds. Four SRVs lifted for a short duration before the bypass valves opened to maintain reactor pressure at normal band. Although the decrease to 4.5 inches initiated a containment isolation signal, the effected valves were closed prior to the event.

One of the two reactor recirculation pumps were started following the scram procedure, approximately 22 minutes after the load reject/scram. The resulting voltage perturbation in the electrical system caused non-vital instrument uninterruptible power supplies (UPS) 2D240 and 2D130 to attempt a transfer to their alternate power supplies. UPS 2D240 did not complete the transfer and the de-energization of its associated instrument distribution panel caused a reactor water cleanup (RWCU) system isolation and pump trip. The reactor building chillers, reactor building Zone II and II HVAC fans, and certain plant computer data points were also lost. Due to the loss of radiation monitors on the refuel floor, Unit 1 refueling activities were halted and the floor was evacuated. The instrument distribution panel power was restored within 25 minutes. Section 4.2 of this report provides additional details on the loss of the UPS.

The maximum cooldown rate was 70°F/hr, well within the plant Technical Specification limits. The drywell temperature increased to 130°F and containment integrity was not affected. Suppression pool (SP) temperature increased by 3°F due to the SRV lifts. However, the process computer SP bulk temperature indication was lost (due to the UPS failure) and entry into the emergency operating procedures was required due to alternate temperature readings exceeded the 90°F limit. The inspector noted that the alternate temperature readings are more conservative (higher) than the bulk SP temperature because of their location in the SP. No indication of fuel damage from the transient was evident from the radiation and effluent monitors or reactor coolant activity readings.

The inspector discussed the event with various licensee personnel including the control room operators and STA present during the transient. The inspector reviewed the licensee's closeout action items from the scram and attended the startup PORC meeting. The inspector concluded the control room operators appropriately responded to the event and that the plant equipment functioned as designed. The licensee took appropriate actions as required by the plant TS during the event.

2.5 Main Generator Seal Oil Spill

On the evening of May 3, 1995, Unit 1 was in cold shutdown and generator's hydrogen cooling system was undergoing a pressure test with nitrogen gas. The seal oil system provides a pressurized source of sealing oil to the generator shaft seals to prevent the escape of hydrogen cooling gas during generator operation. At approximately 8:00 p.m. control room operators received alarms for low seal oil pressure and the emergency seal oil pump started. The control room operators believed the emergency pump started due to a low pressure condition resulting from air in the seal oil system which caused pressure pulsations and vibration of the system's piping. In response to the alarm, a Nuclear Plant Operator (NPO) and the Assistant Unit Supervisor (AUS) were directed by control room operators to attempt a swap of the system's in-service oil filter. The seal oil system has two parallel filters, one of which is selected for service via a three way valve. The operators believed that air trapped in the in-service filter could be the cause of the pressure pulsations. In preparation to swap filters, the NPO and AUS began to vent the filter that they believed was out of service. However, the position indicator on the three way valve was not clear and they began working on the in-service filter. As they attempted to vent the filter, its vent plug was ejected and approximately 300 gallons of seal oil was expelled. Subsequently, nitrogen gas from the generator cooling system pressure test began leaking back through the seal oil system and out the plug's opening. The NPO and AUS evacuated the area and called for assistance. Additional NPOs responded with self contained breathing apparatus and were able to terminate the nitrogen leak by repositioning the three way valve (placing the opposite filter "in-service"). Operations ordered evacuation of all non-essential personnel from the turbine building until Plant Safety could obtain air samples to confirm the building was fit for habitation.

During this event, two NPOs had oil splashed in their eyes and were transported by plant personnel to the hospital for examination. One hour and forty five minutes after the event began, and after cleanup efforts were underway, a third operator had difficulty breathing and was transported by ambulance to the hospital. The three individuals were not seriously injured and returned to the site later the same night.

The inspectors reviewed the scope and details of the licensee's cleanup and recovery efforts. The seal oil that was ejected from the filter covered the seal oil pump skid, associated electrical junction boxes, in addition to cable trays and other equipment on the 699' elevation of the turbine building. An oil mist was reported to have filled the 699' elevation and also have migrated to lower elevations of the turbine building through open floor plugs. The largest volume of spilled oil was contained by the concrete berm which surrounds the seal oil pump skid. The seal oil is chemically non-aggressive and had no impact on the integrity of electrical cables in the area (oil resistant cable insulation). No safety-related equipment was located near the seal oil spill or affected by it. Electrical junction boxes, pump motors, and instrumentation in the area were also verified as not effected by the oil. The turbine building filtered exhaust system and recirculation system were inspected for oil intrusion and no indication of oil was identified.

The inspector observed the equipment near the oil spill for potential ignition sources. Due to the plant's shutdown condition most equipment in the general area of the seal oil skid was not operating. The three seal oil system pump motors are designed for use in combustible environments. In addition, the seal oil skid is surrounded by a temperature activated fire suppression system. The inspector noted that if this event had occurred during generator operation, the consequences could be significant due to the flammable mixture of hydrogen and oil that would be created.

The inspector reviewed the licensee's response to the event, the impact on plant safety, and the reporting criteria used for notification of the NRC. The inspector considered this event potentially significant based on the consequences that might likely to occur with the generator in operation. The inspector noted that the major contributors to this event were the valve indicator design, the filters' vent design, and lack of operator familiarity with the system (due to a history of trouble free operation). Human factors differences between the position indication for the three way valve in Unit 1 and Unit 2 also may have been a contributor. The licensee's immediate response to the event and initiation of an Event Review Team (ERT) for this incident were viewed as a strength. At the close of this inspection period the ERT was still in progress, however, based their progress to date, the inspector concluded that all relevant safety concerns were being addressed. The inspector recognized the licensee's development of an off normal procedure for loss of generator seal oil as a significant safety improvement gained from this event.

3. MAINTENANCE AND SURVEILLANCE (62703, 61726, 92902, 40500)

3.1 Maintenance Observations

The inspector observed and/or reviewed selected maintenance activities to determine that the work was conducted in accordance with approved procedures, regulatory guides, Technical Specifications, and industry codes or standards. The following items were considered, as applicable, during this review: Limiting Conditions for Operation were met while components or systems were removed from service; required administrative approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and quality control hold points were established where required; functional testing was performed prior to declaring the involved component(s) operable; activities were accomplished by qualified personnel; radiological controls were implemented; fire protection controls were implemented; and the equipment was verified to be properly returned to service.

Maintenance observations and/or reviews included:

-- WA S44324, Reactor Disassembly Using Wetlift System, dated March 28, 1995.

-- WA 40743, Install New Motor/Actuation for Valve HV-155F001 HPCI Steam Supply to Turbine Valve, dated March 30, 1995.

-- WA P42232, Inspect and Lubricate Vacuum Relief Valves, dated April 5, 1995. PSV 15704D1

-- WA H40114, LPCI Injection Valve HV151F015B Repair Based on LLRT and Votes Results, dated April 10, 1995.

-- WA S53569, 'E' Diesel Generator Injector Nozzle Replacement, dated April 24, 1995.

-- IC-078-003, Traversing Incore Probe (TIP) Detector Replacement, dated May 8, 1995.

The inspectors concluded the above maintenance work was completed with due concern for plant safety and procedures.

3.1.1 Control Rod Drive Mechanism Changeout

The licensee replaced 20 control rod drive mechanisms (CRDMs) during this outage as part of their CRDM preventive maintenance program. The following procedures were used to perform the changeout:

- NDAP-QA-307, Rev 0, Removal of One or More CRDMs During Operating Condition 5
- MT-055-015, Rev 4, CRD Removal
- MT-055-016, Rev 6, CRD Installation
- MT-055-007, Rev 6, CRD Transfer, Filter Removal and Flush

The inspector observed the removal of several CRDMs on April 7, 1995. The prerequisites for the evolution were met. A safety evaluation dated March 16, 1989, indicated that the required shutdown margin will continue to be met as long as the four surrounding fuel assemblies are removed prior to withdrawal of the control rods. The inspector verified the control room core map tagboard indicated empty fuel cells for the affected control rods. The evolution was controlled in accordance with the requirements of procedure NDAP-QA-0326, Operations With Potential For Draining Reactor Vessel/Cavity. The evolution was monitored by the nuclear system engineer. Health physics personnel were aware of the changing radiological conditions as the CRDMs were being transported from undervessel area to the CRDM rebuild room in the reactor building. Frequent surveys were performed to ensure proper control of high radiation area boundary. The maintenance personnel involved in the changeout operation were well skilled and experienced, performing the work in an efficient manner with appropriate adherence to ALARA dose reduction guidelines.

Based on the work observed, the inspector concluded the CRDM changeout process was well-controlled and monitored, with appropriate coverage by management, engineering and support personnel.

3.1.2 Underwater Installation of Main Steam Line Plugs

On March 29, 1995, the inspector observed underwater installation of the main steam line plugs. The plugs are installed using a rigid pole system from the refueling platform with the help of an underwater camera and lighting. While reviewing the controlled copy of the procedure, the inspector noted that two of the four plugs have been installed, but the steps for the second plug's installation were not signed off in the appropriate location. The Refueling Floor Manager delayed work until the responsible individual could be contacted. After verifying that the step had been completed, the refueling floor manager corrected the signoff and allowed work to restart.

The inspector observed installation of the third steam line plug from the refuel bridge. Good communication between the maintenance crew on the bridge and the Refuel Floor Supervisor, and step-by-step procedure compliance were noted. The skill of the person handling the rigid pole system was very good. The inspector also observed the involvement of a vendor representative, engineering and QA personnel on the bridge, and good health physics coverage. Because this was the first under water installation of the main steam line plugs, the procedure was new and the crew lacked experience with the installation tool. This increased the time required for completion of some tasks, however, the inspector concluded the crew performed in a deliberate and careful manner. Management and supervisory oversight on refuel floor was very good.

3.1.3 TIP Detector Replacement

During a surveillance test to establish the LPRM gain adjustment factors following the Unit 1 outage, the 'D' traversing in-core probe (TIP) detector failed. I&C technicians verified the problem was not in the 'D' detector's instrument drawer and concluded that replacement of the detector itself was required.

The inspector observed the I&C maintenance work and health physics (HP) support for the TIP replacement. Good support by the HP technicians was noted and total dose for the job was kept to 15 mrem. The inspector considered this ALARA effort significant since dose rates in the TIP room reached as high as 20 R/hr during the work. One minor weakness in personnel monitoring was identified during the evolution. Airborne contamination monitoring located in the work area was exposed to contamination while the workers were out of the area. As a result, the dose assigned to the rad workers for this job could have been greater than the dose actually received. This would be a conservative estimate of their exposure and therefore is not a safety concern. The HP staff has recognized that attaching the air sampler to the worker will result in a more representative measure of the workers exposure to airborne contamination.

The 'D' TIP was returned to service and operated properly its first pass, however, during its second run the detector again failed. Further investigation found that a section of the coaxial follower cable in the 'D' TIP drive housing had an open circuit when the detector was fully inserted into the core. The inspector questioned whether the potential for a high worker dose during the TIP replacement was justified by extent of trouble shooting that took place. The licensee stated that a failure of this type was not common and due to the age of the 'D' TIP detector, a failure in the detector or sheathed cable would be likely. The inspector noted that the failure reported was not typical of a detector failure (a loss of sensitivity) and discussed this with I&C supervision. During this failure, detection of the open circuit was difficult because it only occurred with the TIP fully inserted. Licensee personnel stated that future TIP trouble shooting would take into account the lessons learned from this evolution.

The inspector concluded that HP planning and support were effective in keeping the radiation worker dose for this maintenance as low as reasonably achievable (ALARA). The workers were observed to perform the maintenance in a safe, prompt, and efficient manner which helped to minimize their dose. The evolution was well controlled and coordinated by field supervision. Operators entered the applicable TS Action Statement when the TIP ball valves' automatic isolation function was defeated (for ALARA the TIPs were inserted) and the TS allowed outage time was met. The inspector had no further questions.

3.2 Surveillance Observations

The inspector observed and/or reviewed the following surveillance tests to determine that the following criteria, if applicable to the specific test, were met: the test conformed to Technical Specification requirements; administrative approvals and tagouts were obtained before initiating the surveillance; testing was accomplished by qualified personnel in accordance with an approved procedure; test instrumentation was calibrated; Limiting Conditions for Operations were met; test data was accurate and complete; removal and restoration of the affected components was properly accomplished; test results met Technical Specification and procedural requirements; deficiencies noted were reviewed and appropriately resolved; and the surveillance was completed at the required frequency.

Surveillance observations and/or reviews included:

-- SE-259-017, LLRT Personnel Airlock Seal Gap, dated April 19, 1995.

-- TP-255-016, Control Rod Drive Exercising in Condition 4, on April 19, 1995.

-- TP-150-004, RCIC Turbine Overspeed Trip Testing with Auxiliary Steam, on April 19, 1995.

-- SE-124-C02, 18 Month Diesel Generator 'C' Loss of Offsite Power Test During Plant Shutdown, dated April 25, 1995.

-- SO-183-002, Rev 5, 18 Month ADS Valve Manual Actuation, dated May 5, 1995.

-- TP-055-004, CRDM Restoration Following Blade/Drive Replacement, on April 11, 1995.

-- SO-258-003, Semi Annual RPS EPA Breaker Functional Test, on April 20, 1995.

-- SO-251-002, Core Spray Loop A Quarterly Flow Test, on April 19, 1995.

-- SE-100-002, ASME Class 1 Boundary System Leakage Test, on April 27, 1995.

-- TP-264-024, Reactor Recirc 1B Voltage Regulator Stability Test, on May 8, 1995.

Based on observation of selected portions of the above procedures, the inspectors concluded that they were completed with appropriate consideration for safe plant operation.

3.2.1 Diesel Generator Loss of Offsite Power Testing

On April 25, 1995, the inspector observed Emergency Diesel Generator (EDG) 'C' loss of offsite power (LOOP) testing from the diesel bay. The test was originally started in the morning and aborted after identifying that the data recorder for the diesel generator parameters was not started in time. The test was restarted in its entirety after communication/coordination problem (the noisy diesel bay, use of plant paging system vs. headphones) that led to the late start of the recorder was addressed. Certain procedure steps dealing with diesel generator breaker close and trip relay contact functional checks were deleted to simplify the evolution.

The inspector attended the test pre-brief given by the Test Director. The detailed steps for ensuring the timely start of the data recorder were discussed. The inspector observed good command and control of the test, meticulous followup of the procedure, and generally good communication. The system engineer took lead in the diesel bay. As the test progressed he ensured all the crew members were made aware of the progress, the procedure steps that were to be performed and the expected response. The inspector discussed a procedure revision made prior to the retest with the system engineer. The revision deleted checks of certain parallel contacts associated with the EDG's relays that control the output breaker. These checks had been added to the test procedure during this outage to provide additional information on system operation. However, the licensee believed that these checks distracted the individual operating the data recorder during the first test attempt. The function of the EDG output breaker control circuit (encompassing the subject contacts) is tested in accordance with the requirements of TS 4.8.1.1.2d. The licensee stated that functional check of each contact in this circuit is not required since the EDG control circuit is not required to be tested during a logic system functional test. The engineer indicated satisfactory contact operation will be checked in the future under a temporary procedure.

The inspector concluded the licensee's testing satisfied the TS required 18 month surveillance for the diesel generator's loss of offsite power and hot restart capability. The inspector concluded the licensee completed the test in a well controlled and effective manner. The inspector considered the system engineers participation and performance during the test a strength.

3.2.2 Unit 1 Suppression Pool Diver's Inspection

The inspector observed portions of the Unit 1 suppression pool inspection activities conducted during the refueling outage. The inspection was to confirm the absence of debris having the potential to clog emergency core cooling system suction strainers. The activity was coordinated by an engineering test director from PP&L's corporate engineering using an approved test procedure.

During the diver's inspection, the licensee was able to removed some debris from the pool that was previously identified and analyzed as acceptable. New items such as a 5' length of tubing, some sampling wands, tools and various smaller items were identified and removed. Items that were irretrievable included small metallic objects like nuts, a bolt, a weight and a small rod. The licensee concluded that current house keeping requirements and tool control practices are sufficient to prevent items from being dropped in the pool and not accounted for.

The diver identified loose bolting on RHR 'B', 'C', and 'D' pump lower suction strainers. The licensee suspects that the strainer bolts were not appropriately tightened after a preoperational test where the lower strainers were removed to simulate 50% strainer blockage. Licensee evaluations showed that the strainer function under accident conditions would not have been affected by the loose bolting or the newly found debris. The licensee has tightened the loose strainer bolts. The irretrievable items are small heavy objects on the suppression pool floor and not expected to affect the strainers that are at least 8 feet above the floor.

The diver also retrieved a sheet of visqueen, approximately 5'x5', found hanging from the lower RCIC suction strainer bolts. The RCIC suppression pool suction flow path consists of an upper and lower suction strainer, each having 100% capacity. It is possible that suction from the RCIC pump could draw the visqueen onto the lower suction strainer, blocking its flow. The visqueen is of sufficient size to have also blocked the upper strainer. The licensee stated that the visqueen was probably in the suppression pool for an extended period of time, possibly since original construction. The visqueen was removed from the suppression pool and the licensee is continuing to evaluate whether it made RCIC inoperable during past operating cycles.

The inspector found the activity well controlled and safely performed. All personnel involved were knowledgeable regarding the evolution being performed. The licensee's inspection demonstrated their commitment to ensuring the potential for ECCS strainer clogging is minimized at Susquehanna. An evaluation to determine the impact of the visqueen on RCIC operability during past operating cycles is still in progress. Pending an NRC review of this evaluation for past RCIC operability, this issue is unresolved. (URI 50-387;388/95-08-02)

3.2.3 RCIC Overspeed Trip Test

The inspector observed the RCIC overspeed trip test prebrief, preparation, and execution. During the test, the inspector observed two minor personnel performance weaknesses. During preparation for the uncoupled turbine test, a temporary water hose was installed to supply cooling for the barometric condenser and lube oil cooler (normally supplied by the pump discharge). The temporary rubber hose was strung across the uninsulated auxiliary steam spool piece (installed for the test) and had the potential to melt during operation of the turbine and spray down the RCIC skid. Spraying down the skid would result in the spread of contamination and could impart unnecessary thermal stress a hot turbine. An individual waiting to collect pump performance data identified this condition to the test director and subsequently the hose was moved. The inspector considered this a lack of attention to detail by the individual who installed the temporary hose and a good observation by the personnel present for the test.

The second observation concerned a request by the Test Director for the NPO to reset the RCIC trip/throttle valve's thermal overload at the MCC. The NPO mistakenly attempted to reset the thermal overload for a HPCI steam supply valve. The inspector believes this error was caused by less than adequate communication and that it could have been prevented by self checking via the breaker's descriptive label.

The inspector discussed these observations with the individuals present and plant management. There were no immediate safety consequences resulting from these actions however, the inspector considered them to be weaknesses in attention to detail, communication and self-checking. The licensee has included the above incidents in their current review of human performance issues. The inspector had no further questions.

4. ENGINEERING (71707, 37551, 92903, 40500)

4.1 Generator Inadvertent Energization Protection

The April 15, 1995, Unit 2 scram was caused by a generator load reject that occurred when a main generator output breaker in the 500 kV switchyard was automatically opened by breaker flashover/inadvertent energization protection circuitry. This protective circuit is designed to prevent the flashover of open circuit breaker (CB) contacts during generator synchronization (in case of a gas insulated CB failure) or the inadvertent energization of a non-synchronized generator upon misoperation of a CB or motor operated disconnect (MOD). The protective scheme uses position indication on switchyard CBs and MOD switches to enable a current detection circuit on the generator's output line. This protective scheme should sense a configuration with the potential for inadvertent energization of the generator and then check for current flow to the generator. A misconfigured MOD position switch caused the protective circuit to become partially enabled with the generator operating. When operators opened generator output breaker 3T, the enable logic for flashover protection of 3T was complete. Current flow from the operating generator was immediately detected and caused the Unit's remaining output breaker (CB 3N) to open. The current detection circuit does not differentiate between current flow to or from the generator.

Auxiliary contacts in each MOD provide position indication to the protective relay scheme and can be configured to mimic either the position of the MOD (an "A" contact) or the opposite position (a "B" contact). The licensee determined that an auxiliary contact in MOD 3N-S was configured as an "A" contact when it should have been configured as a "B" contact. As a result, the protective circuit for breaker 3T had been partially enabled since the MOD was closed. The licensee believes that the contact may have been misconfigured during past switchyard maintenance, however, because of past switchyard maintenance record keeping practices, the error cannot be definitively traced. Based on review of the protective relay scheme, the inspector considered it reasonable that the misconfigured switch would not have caused this event during the Unit 2 power ascension of following the spring 1994 outage.

The inspector reviewed the flashover protection relay logic and discussed the issue with Nuclear System Engineering (NSE) personnel. The inspector concluded that the licensee had determined the mechanical cause of the load reject, provided timely assessment regarding the auxiliary contacts of other MODs in the Unit 2 switchyard, and was pursuing actions to prevent future events of this nature. In addition, the Unit 1 switchyard MODs were verified to have the correct auxiliary contact configuration before completion of the unit's refueling outage. NSE and PP&L's Relay and Test Division are currently working to improve the lines of communication, procedures, work practices, drawings, and dedicated staff associated with the Susquehanna switchyards. Also, the licensee's reviewed past Susquehanna and industry events resulting from offsite electrical distribution problems to ensure past occurrences are adequately being addressed. No significant problems were identified. The inspector concluded that the licensee was taking appropriate action to prevent the recurrence of plant transients initiated by switchyard problems and had no further questions.

4.2 Loss Of Unit 2 Non-Vital Instrument UPS

Approximately twenty two minutes after the Unit 2 scram on April 15th operators restarted the 'B' reactor recirculation pump to prevent thermal stratification of the reactor coolant. With the offsite distribution system in a normal configuration the start of a recirculation pump results in a voltage dip on its electrical bus. On April 15th, all offsite power for the site was supplied through the 13.8 kV Startup Bus 10 due to planned maintenance associated with Startup Bus 20. With this configuration the voltage dip was greater than usual but did not reach the undervoltage setpoint for the safety related 4.16 kV ESS busses. However, the voltage dip sensed at Unit 2's non-vital instrument uninterruptible power supplies (UPS) was sufficient to cause them rely on backup batteries. The 2D130 UPS battery supplied its loads for a short duration and the UPS transferred to its alternate AC supply when the battery voltage decreased below its nominal value. The battery in UPS 2D240 was inoperable and, as a result, the UPS was not able to transfer to its alternate AC supply. This resulted in the loss of some control room indications and other components as discussed in Section 2.4 of this report. In accordance with ON-217-001, Loss of Instrument Bus, an operator was dispatched to the UPS. Since no faults were indicated, the bus was realigned to its normal supply and indications were restored within 25 minutes. The instrumentation lost was not essential to monitoring the safe shutdown condition of the plant and the ON procedure provided alternate indications for the operators to reference. However, the loss of the indications and components provided an unnecessary complication to the operators while trying to recover the plant post-scram.

The 2D240 and 2D130 UPS were installed to increase the reliability of non-vital instrument buses by providing a battery supported automatic transfer on undervoltage. Each UPS is designed to supply its respective instrument loads from its installed backup battery during a loss of the preferred AC supply (until the preferred source is recovered or until the battery is depleted) and then make a transparent transfer to the alternate AC supply. The instrument bus is normally powered from the preferred AC source via a rectifier/charger, DC bus, a voltage regulator, and an inverter. When an undervoltage condition exists on the preferred source, the internal 250 Vdc battery will begin to carry the loads. If preferred power is not restored, the battery will deplete to below its nominal voltage and the inverter's output breaker opens. The static transfer switch will then provide a virtually instantaneous transfer to the alternate AC supply if it is available.

On April 15th, when the undervoltage condition was created on the preferred supply, UPS 2D240 immediately attempted to transfer to the alternate supply because no battery backup was available. However, since the normal and alternate supplies are ultimately powered from Startup Bus 10 the undervoltage condition was present on both supplies. Per its design, the UPS did not transfer to the alternate supply because of its degraded voltage condition and the instrument panel was therefore not aligned to any supply. When the alternate supply voltage recovered, the UPS static transfer switch could not complete the transfer due to an interlock that sensed a large differential voltage between the supply and load. The UPS functioned as could be expected considering the battery was not available.

The inspector questioned why the UPS was in service with a battery known to be inoperable. During preventive maintenance on December 7, 1994 a battery cell in UPS 2D240 dropped to a low voltage and plans were made to replace the cell. On January 30, 1995, the UPS failed its post-maintenance testing but no additional replacement cells were available. UPS 2D240 was returned to its normal alignment with the knowledge that the battery backup was not available. This information was carried on the Unit Supervisor's turnover sheet pending completion of the work authorization to replace the battery.

The Susquehanna FSAR, Section 8.3.1.8, states "Each instrument AC power supply consists of one uninterruptible power supply (rectifier/charger, inverter, static transfer switch), a dedicated 250 Vdc sealed maintenance-free battery system, an external maintenance bypass switch panel, and a 208/120 V distribution panel." Further the FSAR states "If the UPS is inoperable or is to be removed from service for maintenance or testing, the external maintenance bypass switch is positioned to bypass the UPS and supply the distribution panel directly from the alternate supply." The inspector noted that the UPS, without its battery, will effectively isolate the distribution panel in response to a simultaneous undervoltage condition on both the preferred and alternate power supplies. Operator action is then required for recovery of the instrumentation. In comparison, with the maintenance bypass aligned, the supply is fixed and no operator action is required if the alternate supply bus recovers.

After reviewing off-normal procedure ON-217-001 and interviewing plant control operators, the inspector concluded that there was no direct impact on plant safety. Plant systems affected by the loss of the instrument distribution panels responded as expected. However, the loss of UPS 2D240 provided an unnecessary complication during the post-scram recovery period. Currently,

the four UPS at SSES have operable batteries installed and the licensee is evaluating an increased replacement frequency (every 3 years vs. 5 years) in addition to actions intended to extend their service life.

The inspector concluded that the direct safety impact of the post-scram UPS 2D240 failure was low. However, normal alignment of the degraded UPS resulted in an unnecessary complication for the control room operators during the scram recovery because anomalous indication occurred and systems realigned. Also, operator action was necessary to restore power to the effected instrumentation. If the UPS had been aligned as described in the FSAR, the April 15th voltage drop would not have caused isolation of the instrument AC distribution panels. Returning UPS 2D240 to its normal alignment with an inoperable battery rather than using the maintenance bypass as described in the FSAR was a deviation from the FSAR commitment. (DEV 50-388/95-08-01)

5. PLANT SUPPORT (71750, 71707, 92904, 40500)

5.1 Radiological and Chemistry Controls

During routine tours of both units, the inspectors observed the implementation of selected portions of PP&L's radiological controls program to ensure: the utilization and compliance with radiological work permits (RWPs); detailed descriptions of radiological conditions; and personnel adherence to RWP requirements. The inspectors observed adequate controls of access to various radiologically controlled areas and use of personnel monitors and frisking methods upon exit from these areas. Posting and control of radiation areas, contaminated areas and hot spots, and labelling and control of containers holding radioactive materials were verified to be in accordance with PP&L procedures. Health Physics technician control and monitoring of these activities was satisfactory. Overall, the inspector observed an acceptable level of performance and implementation of the radiological controls program.

The inspector discussed ALARA program implementation during the Unit 1 8th refueling outage with the Health Physics Supervisor. The licensee met the estimated man rem exposure goal for this outage which was 200 man rem. The licensee's use of "ALARA in Progress" review helped in achieving the goal. The inspector reviewed the individual tasks that exceeded the estimated man rem exposure goals, the root cause of such departure and the lessons learned items with the Health Physics supervisor. Snubber testing/inspection, the refuel floor activities, and the control rod drive and undervessel work were three task categories that exceeded the estimated goals. The licensee is currently reviewing these jobs to determine needed ALARA improvements. Based on higher than expected contamination levels in some areas of the turbine building and higher frequency for personnel contamination events at the beginning of the outage, the licensee made changes to contamination control measures. The Health Physics supervisor explained that the final PCR number (0.8 per 1000 man hour work) was consistent with the past experience. Based on the above review, the inspector concluded the licensee implemented an adequate ALARA program during the outage.

5.2 Emergency Plan and Implementing Procedures

The inspector reviewed recent changes to the Emergency Plan and Emergency Plan Implementing Procedures. The inspector noted that Revision 21 to the Emergency Plan changed the method for dissemination of information to the public. Previously, emergency instructions and evacuation maps were distributed to residents, motels, hotels, and recreation areas in the Emergency Planning Zone (EPZ) by mail and were included in telephone directories distributed within the EPZ. The licensee now intends to include the instructions and maps only in the telephone directories distributed within the EPZ. This change in Revision 21 is still being reviewed by the NRC. The other changes reviewed were found not to decrease the effectiveness of the Emergency Plan and, therefore, were acceptable. The list of reviewed changes is included as Attachment 1 to this report.

5.3 Security

PP&L's implementation of the physical security program was verified on a periodic basis, including the adequacy of staffing, entry control, alarm stations, and physical boundaries. These inspection activities were conducted in accordance with NRC inspection procedure 71707. The inspector reviewed access and egress controls throughout the period. No significant observations were made.

6. SAFETY ASSESSMENT/QUALITY VERIFICATION (40500, 90700, 90712, 92700)

6.1 Open Item Followup

(Update) URI 50-387/92-02-01 (Common), IER Program Weaknesses

This item was left unresolved following a hydrogen ignition and contamination injury on January 18, 1992. The inspector was concerned that the licensee's industry experience review program may not have been adequate since certain generic correspondence were not addressed. Specifically, Information Notice 81-27, Flammable Gas Mixture in the Waste Gas Decay Tank in PWR Plants; Generic Letter 79-38, BWR Offgas Systems Pertaining to Explosions; and IE Bulletin 78-03, Potential Explosive Gas Mixture Accumulations Associated with BWR Offgas System Operations.

In response to the unresolved item, the licensee did a review of their Industry Events Review Program (IERP) and a sample survey to determine the effectiveness of the program. Prior to initial startup of Units 1 and 2, PP&L reviewed the IE Bulletins and Generic Letters that were identified by the NRC as required to be addressed. Similarly, the NSSS vendor identified issues that needed to be addressed prior to startup. As a result, generic correspondence that applied to operating reactors issued prior to startup were addressed on a case-by-case basis.

The licensee's survey included a review of a random sampling of 40 NRC Information Notices issued between 1979 and 1992, and nine IE Bulletins issued between 1977 and 1983 for adequacy of evaluation. This survey identified three inadequate reviews of Information Notices, two of which were PWR events.

Although current program screens the PWR events for applicability, the licensee determined further review of older Information Notices on PWR events was required. Based on the survey results, the licensee concluded the past IER evaluations were of high quality.

The licensee's program is delineated in procedure NDAP-QA-725, Rev 2, Industry Event Review Program. Based on this procedure, Nuclear Licensing group (currently under Nuclear Engineering) has overall responsibility of coordinating the implementation of the program. An IERP coordinator has been assigned who performs a preliminary screening review of all NRC Information Notices, IE Bulletins, 10 CFR Part 21 reports, Generic Letters, GE SILs and TILs, and other industry issued generic correspondence except for INPO SOERs which are handled by the Operating Experience group in Nuclear Assessment Services (NAS). For IE Bulletins and Generic Letters the IERP coordinator tracks them for completion of needed actions which are coordinated separately by the group responsible for responding to the NRC. Additionally, the Independent Safety Evaluation Services (ISES) group in NAS performs an independent investigative assessment of all GE SILs and SALs and NRC Information Notices. ISES also reviews the INPO network information on plant events for applicability to SSES and required followup for lessons learned.

The inspector reviewed the IERP program review and survey results, NDAP-QA-0725, and had discussions with the IERP coordinator. While the program appeared acceptable, the inspector noted that licensee's review did not identify any root cause for not addressing the three industry event documents identified in the NRC inspection report and if those documents were indeed later reviewed for applicability. Upon inspector's questions, the licensee indicated that these items were reviewed and found to require no action. Also a recent condition report (95-198) on a security event identified that Generic letter 91-03, Reporting of Safeguards Events, was not incorporated in licensee's procedure NDAP-QA-720, Rev 1, Station Report Matrix and Reportability Evaluation Guidance. At the end of the inspection period the licensee was reviewing disposition of GL 91-03. This unresolved item will remain open pending the licensee's clarification of this question.

(Closed) VIO 50-388/92-22-01, Uncontrolled Safety System Insulation Removal

This violation was issued as a result of the licensee's removal of insulation from the Unit 2 HPCI and RCIC systems with the unit at 60% power. No procedure or instruction was used, and the insulation was removed without any prior knowledge or authorization of Plant Operations. In its response to the Notice of Violation, the licensee stated that the removed insulation was reinstalled and room coolers were operated to decrease room temperature. To prevent recurrence, a planning directive was issued to clarify the control requirements for insulation, and all planning and production organizations were trained on the directive.

A Nuclear Department Procedure MT-AD-513, Rev 0, Reflective and Thermal Insulation Control Process at SSES, was issued on July 5, 1994 to formalize the procedure and controls for plant insulation. This procedure requires that all removal/installation of existing insulation will be requested via a Scaffold/Insulation Work Request Form, and will be tracked. All insulation related support documents shall be routed through the Planning Group for review, who will determine the effects of insulation work on equipment and system operation and operability. Additionally, all insulation work activities, especially the removal of existing insulation will be controlled and documented through the Equipment Release Form (ERF) process, thus, requiring Operations review and approval.

The inspector reviewed the above procedure and the plant deficiency identification system for possible recurrence of the event since the procedure was in place on July 5, 1994. The plant tour performed by the inspectors in the reactor building prior to the Unit 1 8th refueling outage did not identify any premature removal of insulations. The inspector concluded the licensee implemented adequate procedural controls to prevent recurrence of the event. This item is closed.

(Closed) URI 50-387/90-12-03 EDS Single Failure Evaluation And Reporting

In 1990 the licensee identified several issues concerning the capability of the electrical distribution system to meet its design basis. The technical issues raised in Inspection Report (IR) 90-12 were addressed by the July 1990 NRC Electrical Distribution System Functional Inspection (IR 90-200). However, the unresolved item also questioned the fact that PP&L was reporting design deficiencies under 10 CFR 50.9 versus 10 CFR 50.72 and 50.73. The inspectors were concerned that the licensee's 50.9 reports did not contain sufficient technical information, or discussion of the safety significance and corrective actions, needed for the NRC to properly assess the plant specific and generic safety considerations in a timely manner. Pending the licensee's actions to investigate this issue the issue was left unresolved.

Since 1990, PP&L has made a number of changes to clarify how design and qualification issues are identified, evaluated, and reported to the NRC. An Engineering Deficiency Report (EDR) process was created specifically for documenting technical questions raised during engineering reviews. In March 1995, PP&L combined the EDR process with other programs having similar requirements to evaluate safety significance, operability, and reportability of identified conditions. The Non-conformance Report (NCR), Significant Operating Occurrence Report (SOOR) and EDR programs were replaced by the unified Condition Report (CR) process. The CR process is intended to ensure a consistent approach is used in addressing and resolving potential safety, operability, and reportability concerns. NRC Inspection Report 50-387/95-80 addressed the CR process in greater detail.

The inspector reviewed the current administrative procedures that establish the licensee's program for identification, evaluating, reporting, and correcting conditions adverse to safety or quality. Specifically, NDAP-QA-0702 on Condition Reports, NDAP-QA-703 on Operability Determinations, and NDAP-QA-0720 on Reportability Determinations were reviewed. Based on this review the inspector concluded that the licensee has taken substantial steps to improve this process since the unresolved item was opened and therefore this item is closed.

(Closed) URI 50-387/90-12-01 ECCS Keepfill Check Valve Leakage

Inspection Report 90-12 raised issues regarding the potential for contaminated water from the suppression pool to leak into the non-safety related condensate transfer system through the RHR and Core Spray system keepfill check valves during certain post-LOCA scenarios. In April 1993, during review of the licensee's disposition for this issue, the inspector noted that PP&L's calculations showed a very low leakage rate from the keepfill check valves could challenge 10 CFR Part 100 dose limits at the site boundary. The inspector was concerned because the keepfill check valve surveillance acceptance criteria was based on limiting ECCS injection flow losses and did not verify that the leakage was less than required by the site boundary dose calculations. A point of contention was that the calculations assumed the leakage would result in a gaseous release directly to the atmosphere, whereas the postulated check valve leakage would actually be a liquid release into the non-seismic condensate transfer system assumed to fail outside containment. Discussions with the Office of Nuclear Reactor Regulation (NRR) indicated that the secondary containment bypass leakage typically of concern was gaseous and not liquid. Due to the generic question regarding the significance of liquid secondary containment bypass leakage, NRC Region I formally requested technical review of the issue by NRR in a letter dated July 29, 1994. The issue of secondary containment bypass leakage via a liquid pathway is still being reviewed by NRR (TAC Number M86276). Since the technical issue is being addressed and tracked by NRR, the inspector determined that administrative closure of the duplicate tracking as an unresolved item is not necessary. Appropriate actions will be taken based on the outcome of NRR's generic review of this issue. This unresolved item is closed.

7. MANAGEMENT AND EXIT MEETINGS (30702)

7.1 Resident Exit and Periodic Meetings

The inspector discussed the findings of this inspection with PP&L station management throughout the inspection period to discuss licensee activities and areas of concern to the inspectors. At the conclusion of the reporting period, the resident inspector staff conducted an exit meeting summarizing the preliminary findings of this inspection. Based on NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain information subject to 10 CFR 2.790 restrictions.

7.2 Other NRC Activities

The following region based NRC inspection activities took place during this period:

Dates	Report No.	Inspection Procedure
May 8-12	IR 95-80	40500, Effectiveness of Licensee Controls in Identifying, Resolving and Preventing Problems
May 1-5	IR 95-11	84750, Radioactive Waste Management

April 10-14	IR 95-10	83750, Occupational Radiation Exposure
April 3-7	IR 95-09	73753, Inservice Inspection
Note 1	IR 95-08	82701, Status of EP Program

Note 1: The review of the Emergency Plan and Implementing Procedures was conducted in the Region I office and a feeder was provided for the resident inspectors' report.

Attachment 1

List of the Emergency Plan and Implementing Procedures Reviewed

Procedure Number	Procedure title	Revision(s) Reviewed
	Emergency Plan	21
EP-PS-100	Emergency Director/CR	9, 10
-Tab A		4
-Tab B		6
-Tab C		3
-Tab D		4, 5
-Tab E		1, 2
-Tab 7		2
-Tab 8		5
-Tab 9		4
EP-PS-101	Emergency Director/TSC	11
-Tab D		3
-Tab 5		7
-Tab 7		2
-Tab 8		5
-Tab 9		4
-Tab 10		4
EP-PS-102	Technical Support Coordinator	7, 8, 9
-Tab E		2
-Tab I		1
-Tab J		1
-Tab K		0
-Tab 2		4, 5, 6
-Tab 4		0
-Tab 5		5, 6
-Tab 6		5, 6, 7
-Tab 9		2
-Tab 10		0, 1
EP-PS-103-Tab 2	Operations Coordinator	4, 5, 6
-Tab 5		5, 6, 7
-Tab 6		5, 6, 7
-Tab 8		4
EP-PS-104	Rad Protection Coordinator	6, 7, 8, 9
-Tab B		1
-Tab C		3
-Tab D		1, 2
-Tab F		2
-Tab G		3
-Tab H		2
-Tab I		3

Attachment 1

Procedure Number	Procedure title	Revision(s) Reviewed
-Tab 2		4, 5, 6
-Tab 3		1
-Tab 5		5, 6, 7
-Tab 6		5, 6, 7
-Tab 7		1, 2
-Tab 8		4, 5
-Tab 10		4
-Tab 12		4
-Tab 13		1
-Tab 14		2
-Tab 15		0
EP-PS-105	TSC Dose Calculator	4, 5, 6, 7
-Tab B		5, 6
-Tab C		2
-Tab D		3, 4
-Tab F		1
-Tab I		1
-Tab 2		4, 5, 6
-Tab 5		5, 6, 7
-Tab 6		5, 6, 7
-Tab 7		1, 2
-Tab 8		4, 5
-Tab 9		5, 6, 7
-Tab 10		4, 5
-Tab 11		0, 1, 2
-Tab 15		3
EP-PS-132-Tab 5	OSC Coordinator	4, 5
EP-PS-200	Recovery Manager	9
-Tab D		2
-Tab E		2
-Tab 5		7
-Tab 7		2
-Tab 8		5