February 25, 2000

Mr. Robert G. Byram
Senior Vice President - Nuclear
PP&L, INC.
Susquehanna Steam Electric Station
2 North Ninth Street
Allentown, Pennsylvania 18101

SUBJECT: NRC TEAM INSPECTION REPORT NO. 05000387/99013 AND 05000388/99013

Dear Mr. Byram:

This refers to the NRC Corrective Action Program Team Inspection conducted at your Susquehanna Steam Electric Station (SSES) Units 1& 2 reactor facilities from December 13, 1999, to January 13, 2000. This inspection included evaluation of the corrective action program effectiveness. The enclosed report presents the results of this inspection. The preliminary findings of the team's onsite effort were discussed with Mr. B. Shriver, Vice President Nuclear Operations, and others of your staff on December 17, 1999, and in a exit held at the site on January 13, 2000.

Overall, the team concluded that you had an acceptable corrective action program to identify conditions adverse to quality. Your own audits and assessments of your corrective action program were thorough, detailed, and critical, and identified several areas that warrant your attention. Our review confirmed the same general themes as documented in the enclosed report.

Based on the results of this inspection, the NRC has determined that three Severity Level IV violations of NRC requirements occurred. Your staff's actions to add all three violations into your corrective action system were reviewed during this inspection and we found those actions acceptable. Therefore, these violations are being treated as Non-Cited Violations (NCVs), consistent with Appendix C of the Enforcement Policy. The first NCV involved a delay of five months for an operability determination for the Standby Liquid Control system to be incorporated into plant operations. The second NCV involved an inadequate corrective action response to a previous violation of the Maintenance Rule Scope. The third NCV involved non-conforming material extent-of-condition.

All three violations are considered closed and no response to this letter is required. If you contest the violations or severity level of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region I, the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001, and the NRC Resident Inspector at the Susquehanna Steam Electric Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

Sincerely,

/RA/

Wayne D. Lanning, Director
Division of Reactor Safety

Docket Nos. 05000387; 05000388

Enclosure: NRC Team Inspection Report No. 05000387/99013 and 05000388/99013

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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos:	05000387, 05000388
License Nos:	NPF-14, NPF-22
Report No.	05000387/99013, 05000388/99013
Licensee:	Pennsylvania Power and Light Company 2 North Ninth Street Allentown, Pennsylvania 19101
Facility:	Susquehanna Steam Electric Station
Location:	P. O. Box 35 Berwick, PA 18603-0035
Dates:	December 13, 1999 through January 13, 2000
Inspectors:	George W. Morris, Reactor Inspector, DRS, Team Leader Gregory V. Cranston, Reactor Inspector, DRS, Asst. Team Leader Joseph M. D'Antonio, Operations Specialist, DRS Laurie A. Peluso, Health Physicist, DRS Alan J. Blamey, Resident Inspector, DRP
Approved by:	William H. Ruland, Chief Electrical Branch Division of Reactor Safety

TABLE OF CONTENTS

PAGE

EXECUTIVE SUMMARY

Susquehanna Steam Electric Station (SSES), Units 1 & 2
NRC Inspection Report 05000387/99013, 05000388/99013

Introduction

An onsite corrective action team inspection was conducted at the Susquehanna Steam Electric Station Unit 1& 2, the corporate PP&L office in Allentown and the Region I offices in King of Prussia during the period of December 13, 1999 to January 13, 2000. The inspection included an evaluation of the effectiveness of the corrective action program to identify, evaluate and correct conditions adverse to quality.

Problem Identification

- In general, PP&L appropriately identified problems and entered them into a corrective action mechanism. Formal investigations and assessments, such as scram investigations and independent safety engineering group (ISEG) assessments, were thorough and identified plant and human performance issues beyond the immediate causes of the scram.

- PP&L failed to perform a timely operability determination for the standby liquid control (SLC) system during air sparge. A non-cited violation (NCV) was issued for failure to timely inform the operating staff of a determination that concluded system inoperability.

- PP&L did not identify the safety-related remote shutdown panel (RSP) transfer switch functions during their corrective action of a previous NRC violation, which identified that the bypass indication system was not in the maintenance rule scope. Failure to identify and include the safety-related functions of the RSP resulted in PP&L excluding the RSP from July 10, 1996 to January 10, 2000. An NCV was issued for inadequate corrective action.

- Examples were noted of human performance, work planning, or coordination issues which should have been addressed by a condition report (CR) but were not until prompting was provided by a licensee manager, auditor or NRC staff. Other examples were identified where CR generation was not timely.

- The team concluded that PP&L was not consistently meeting the industry guidance and procedure requirements for operability screenings and determinations. This resulted in a minor violation due to failure to follow the CR procedure requirements for not promptly submitting the CR for an operability screening.

- The team identified that condition report due dates were sometimes revised without approval. About 12 condition report action (CRA) dates were changed per week. Maintenance stopped this practice in November 1999.

Operating Experience Review Program

- The present industry operating experience program relies primarily on discussions during the initial screening of new industry experience reviews. However, once the event is determined to be applicable to PP&L, the issue is processed through the condition report system to provide a more detailed review and tracking of potential concerns.

- Industry events review program that existed in the late 1980s and early 1990s failed to remove non-conforming components. Those same components continue to challenge the plant. The failure of the Unit 2 "A" main transformer neutral bushing and the Unit 1 reactor core isolation cooling (RCIC) leak detection temperature switch resulted, in part, because of ineffective control of those non-conforming components. An NCV was issued on this failure to prevent the installation or inadvertent use of non-conforming materials, parts or components.

<u>Self-Assessment Activities</u>

- In general, significant facility self-assessment activities produced by Nuclear Assessment Services (NAS) are thorough, detailed, and critical. ISEG surveillances and investigations were also self critical and thorough. However, deficiencies documented in self-assessments in the past have not always resulted in action to correct the identified problems. SSES initiated a multi-focus Corrective Action Program (CAP) Improvement Plan to address the deficiencies identified by internal and external identified weaknesses in the present CAP.

- The failure of most functional units to implement the requirements of the functional unit self-assessment program was identified, both by the NRC team and your Decision 2000 process, as a program deficiency and entered into the correction action program.

<u>Onsite and Offsite Review Committees</u>

- The plant operations review committee (PORC) and the Susquehanna review committee (SRC) demonstrated a critical, probing, and questioning attitude. Overall, implementation of the independent review organizations continue to challenge the effectiveness of the CAP. The management review team (MRT) was slow to respond to recent responsibility changes, however they effectively implemented most of the required tasks.

<u>Corrective Actions for Non-Cited Violations</u>

- Overall, the licensee's implementation regarding corrective actions for NCVs was acceptable. NCVs were entered into the corrective action program, as required. Corrective actions were properly implemented on closed CRs. However, in one instance, the licensee review of the main steam isolation valve (MSIV) leakage was weak regarding root cause analyses, extent of condition reviews, actions to prevent recurrence and timeliness.

<u>Use of Risk Insights</u>

- PP&L’s proposed use of risk insights to assist in prioritizing attention on risk significant condition reports could develop into a useful tool to minimize plant risk.

- Although PP&L had identified decreasing margins on the high risk reactor water cleanup (RWCU) isolation valves, you extended the completion date of required internal inspections of those valves during the May 1999 forced outage at Unit 1 without reviewing the risk of extending those inspections.

Report Details

Introduction

An onsite corrective action team inspection was conducted at the Susquehanna Steam Electric Station Unit 1& 2, the corporate PP&L office in Allentown and the Region I offices in King of Prussia during the period of December 13, 1999, to January 13, 2000. The overall objective of the inspection was to assess the effectiveness of the Nuclear Department organization's performance in supporting safe plant operations. The inspection included evaluation of the effectiveness of the corrective action program to identify, evaluate and correct conditions adverse to quality.

The inspection focused on four broad functional areas of your organization: Operations, Maintenance, Engineering and Plant Support. SSES initiates approximately three thousand condition reports (CRs) per year and assigns each one of four significance levels. The team selected around 30, mostly significance level 1 or level 2, CRs from each functional area for further review. The team also reviewed a variety of audits, surveillances and self-assessments prepared by your staff. The team used this, and other information gained from interviews with your staff, to assess the effectiveness of your corrective action program and related activities.

The assessment reviewed activities in the following six subjects in each functional area:

1 Problem Identification, Evaluation and Resolution
2 Operating Experience Review Program
3 Self-Assessment Activities
4 Onsite and Offsite Review Committees
5 Corrective Actions for Non-cited Violations
6 Use of Risk Insights

1 Problem Identification, Evaluation and Resolution (40500)

a. Scope of Inspection

The team reviewed the effectiveness of the corrective action program as found in various operating, maintenance, engineering, and plant support functional departments, by reviewing a sampling of the following documents:

- Condition Reports
- Audits and Surveillances
- Operations Problem Reports (Operator Work-arounds)
- Bypasses (Temporary Modifications)
- Plant Condition Problem Report (PCPR)

This included a review of:

- Operability determinations
- Assigned significance level
- Root cause evaluations
- Resolution of identified problems
- Assigned priority of corrective actions

- Extent of condition reviews

b. Observations and Findings

b.1 Generation of Condition Reports

The PP&L Nuclear Department staff may identify concerns for entry into the corrective action program (Condition Report Program) either by individual observation, formal program audits, surveillances and assessments, or through their Employee Concerns Program.

The team noted some examples where plant problems were identified by your staff but condition reports (CRs) were not written, or not promptly written, as required by procedure NDAP-QA-0702, “Condition Reports.” Interviews conducted by the team indicated some degree of confusion or lack of understanding of procedural requirements by your staff. Examples were identified both by the NRC and by your staff through your Nuclear Assurance Services reviews.

- During this inspection, your staff was monitoring an intermittent speed control oscillation in the 2A Recirculation Pump and generating a CR each time an oscillation occurs. Some instances were observed both by the NRC and by your Independent Safety Engineering Group (ISEG) where a speed oscillation had occurred but had not been documented by a CR. PP&L manually shutdown Unit 2 on December 17, 1999, to address the 2A pump seal leak.

- Work was being performed in the service water building requiring floor gratings to be covered for foreign material exclusion (FME) concerns; the Unit Supervisor noted that this conflicted with flood protection concerns and had the coverings removed. The Operations Manager prompted the Unit Supervisor to generate a CR for these conflicting requirements.

- The NRC had identified on November 19,1999, that the Unit Supervisor had not generated a CR upon discovering that Unit 1 had unknowingly entered a limiting condition for operation (LCO) defined in Technical Specification 3.6.2.1, due to high suppression pool temperature. This was found after the LCO condition had been cleared. The NRC questioned the independent safety analysis group (ISEG) on this issue and determined that the LCO was entered after the fact. ISEG generated CR 216976 for this issue.

- The NRC identified that on November 9, 1999, maintenance had identified 14 Agastat relays in the “A” emergency diesel generator (EDG) safety-related control logic with loose wiring terminations on the relay bases. During this time the “A” EDG was removed from service; however, similar relays are also used in the control circuits for the “B,” “C,”, “D” and “E” EDGs. Three days later, on November 12, 1999, this condition was documented on CR214791.
- On September 17, 1999, maintenance personnel did not document that the “D” emergency service water (ESW) pump motor was experiencing vibrations in the alert range. One week later, maintenance personnel determined that the upper

motor vibration had increased to the required action range and the “D” ESW pump was declared inoperable. Condition report 204514 documented the failure to properly identify the high vibrations on September 17, 1999.

- The resident inspectors discussed the spray pond array valve design basis, the 1994 array dynamic testing and CR 210803 with system engineering on October 29, 1999. Based on this discussions and further analysis, Allentown engineering determined that the system alignment during the testing of these valves did not represent full design basis conditions. PP&L generated condition report 216927 on November 22, 1999.

These failures to timely generate condition reports constitutes a violation of minor significance and is not subject to formal enforcement action.

b.2 Timeliness of Operability Determinations

Operability Process Overview

PP&L’s station procedure NDAP-QA-0702, “Condition Report” and NDAP-QA-0703, “Operability Assessment and Request for Enforcement Discretion” provides the basis for determining equipment operability. NDAP-QA-0702 states that “as soon as a condition is known or presumed, the CR shall be written and submitted promptly.” NDAP-QA-0703 allows the shift supervisor to make an initial operability call and request an engineering follow-up operability determination to confirm the initial operability screening. The timeliness of this follow-up operability determination must be commensurate with the safety significance and should be completed within 14 days.

- Initial Operability Screening

  The following CRs may have been unnecessarily delayed:

  CR 94198 discussed industry information that could lead to standby liquid control operability issues during air sparge operation. This condition report did not have an operability screening performed and is further discussed in section b.3.

  CR 213284 discussed broken shunt strap on spare 4 KV breaker. This was found November 8, 1999, and the shift supervisor completed his initial review on November 10, 1999.

CR 215886 discussed main steam isolation valves (MSIVs) that have original stems which may be susceptible to failure. This was discovered November 11, 1999. Allentown engineering reviewed it on November 16, 1999. The shift supervisor completed his initial review on November 18, 1999.

CR 216937 discussed failures of two secondary containment isolation dampers. This was caused by unauthorized lubrication on the solenoid valve. Allentown engineering issued the CR on November 22, 1999, and the shift supervisor reviewed the CR on November 24, 1999.

These delays are contrary to PP&L procedure NDAP-QA-0702 "Condition Report" which require, in part, that a CR shall be written and submitted as soon as a problem is identified. In addition, the NRC has provided industry guidance through Generic Letter 91-18 revision 1, "NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions", which cites approximately 24 hours as an acceptable time to preform the initial operability screening.

- Follow-up Operability Determinations

The team reviewed the timeliness of thirty operability determinations completed during December 1999. The results of this review identified that 57% were completed within 7 days; 30% were completed within 14 days and 13% exceeded the 14 day procedural requirement. The team further reviewed several of the operability determinations that exceeded seven days. We identified three Technical Specification (TS) structures, systems or components (SSC) in which the time allowed for engineering to complete the operability follow up determination was much greater than the TS Allowed Outage Time (AOT).

CR 219138 Standby Gas Treatment (SGT) System fan "B" bearing nearest the fan has no oil in the sight glass. This is a recurring problem.

This condition was identified on December 7, 1999; PP&L assigned a due date of December 21, 1999, (14 days) for the operability follow up. The follow up was completed on December 20, 1999, 13 days later. TS 3.6.4.3, Standby Gas Treatment (SGT) System has an AOT of 7 days.

CR 220103 DC distribution panel 1D622 has developed a negative ground as indicated by the ground lights.

This condition was identified on December 11, 1999; PP&L assigned a due date of December 26, 1999, (15 days) for the operability follow up. The follow up was completed on December 25, 1999, 14 days later. TS 3.8.7, Distribution System - Operating has an AOT of 2 hours.

CR 221470 Unit 1, Division I, 250 VDC battery 1D650, cell number 80, has a positive post seal lifted approximately 1/4 inch.

This condition was identified on December 17, 1999; PP&L assigned a due date of January 1, 2000, (15 days) for the operability follow up. The follow up was completed on December 29, 1999, 12 days later. TS 3.8.4, DC Sources - Operating has an AOT of 2 hours.

Generic Letter (GL) 91-18, "Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions," provides generic guidance to the industry. This GL states that for systems, structures or components (SSC) in Technical Specifications (TS), the allowed outage times (AOT) contained in TS generally provide reasonable guidelines for safety significance.

The team concluded that PP&L normally assigns the maximum time allowed by the NDAP-QA-0703 to determine operability; seldom is discrimination made based on TS AOT. The team did not identify any operability determination, during this inspection, that resulted in a SSC being inoperable for a time period greater that the AOT. This failure to formally tie the maximum allowed time for a follow-up operability determination to its TS AOT was considered another example of a weakness in your corrective action program.

b.3 <u>Timeliness of Completing Corrective Actions</u>

a. Standby Liquid Control Air Sparge Operation

One example was noted of a failure to perform corrective actions within the required time frame without an approved extension. On April 12, 1999, PP&L was informed that the standby liquid control (SLC) pumps may become degraded while air sparge is in operation. The air could become entrained in the process flow and degrade the pump capability. PP&L has previously experienced degraded SLC pump operation due to air binding. The time line of PP&L handling this issue was as follows.

July 20, 1999 CR 94198 Actions were approved to

(a) Declare the SLC inoperable during air sparge operation,
(b) Provide guidance on SLC recovery from sparging during a DBA event, and
(c) Train the operators on these procedure changes.

August 27, 1999 Target completion date for the above actions.

December 23, 1999 NRC identifies that the above actions are not completed.

January 15, 2000 A new date specified by operations to complete the above actions or conclude that the SLC would be operable during air sparge operation. There was no extension request approval form in the package to allow this work or date change.

The shift supervisor did not perform an operability determination on this condition report. Prior to November 29,1999, (NDAP-QA-0702, revision 7) the shift supervisor did not typically perform operability determination on industry experience CRs. On July 20, 1999, PP&L concluded, through the normal review of this condition report, that the SLC system would be inoperable during sparge air operation. PP&L did not effectively communicate this to the operations shift, nor were procedures changed to reflect this condition. Therefore, between the time engineering had determined the SLC system would be inoperable and this inspection, five months had passed where the system had not been declared inoperable during the 13 sparging operations conducted over that period. This failure to identify a confirmed operability concern to the operating department was contrary to the requirements of NDAP-QA-0703 and is a Severity Level IV violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions but is being treated as a non-cited violation in accordance with Appendix C of the NRC Enforcement Policy. PP&L initiated a level 2 condition report 225871, to evaluate the reviews this operating experience report / condition report received. **(NCV 05000387 & 05000388/99013-01)**

b. Core Spray (CS) and Residual Heat Removal (RHR) Low Pressure Permissive Switches

During the last Unit 2 refueling outage (2R09) PP&L installed new pressure switches for the CS and RHR low pressure permissive instrumentation. During testing of the switches maintenance identified that the switches would exhibit a set point shift of approximately 5 to 10 psi downward during a very rapid depressurization. Condition report 92587 determined that the switches were operable. However, CRA 192251, was issued to evaluate the application of the instruments to verify the performance will meet the design criteria and that operations is bounded in the current accident analysis. The original due date for this action was October 29, 1999, five months after the Unit 2 startup from the refueling outage. This date was later extended to January 31, 2000.

PP&L should have taken more timely corrective actions to ensure the plant was within the design and licensing bases prior to unit startup. The team noted that your follow-up analysis showed that the plant was within your licensing and design basis during the startup.

c. Maintenance Control of Corrective Action Dates

The team noted that the last performance discharge test of station battery 2D630, determined that the battery capacity had fallen to 83.6%. Because of this degradation, TS Surveillance Requirement 3.8.4.8 requires the battery to be tested within one year of the original test. PP&L determined that they would replace this battery, instead of testing the battery, before the next required test date (March 22, 2000). Condition report 92570, action 2, (CRA 193218) was assigned to maintenance to replace the battery by February 28, 2000.

Once the CRA was assigned to maintenance, the maintenance data administrator revised the due date to meet the plant component problem report (PCPR) date of June 1, 2001. The team identified that this is a common practice within maintenance. The maintenance data administrator changes approximately 12 CRA dates per week to coincide with the PCPR dates assigned by scheduling. The practice of revising CRA due dates, without the required extension approvals as specified in NDAP-QA-0702, "Condition Reports" is considered a violation of minor safety significance. PP&L plans to replace station battery 2D262, during the week of January 31, 2000. Maintenance is no longer changing the CRA due date without processing an extension as now required in NDAP-QA-0702, Rev. 7.

b.4 Effectiveness of Corrective Actions

The NRC inspection team reviewed the licensee's ability to prevent recurrence of past problems. This review identified several recurring issues. The team determined the reason for recurrence is related to the timeliness of corrective action completion and the lack of proper root causes and causal factors identification. The following examples were noted during this inspection.

- Recurrent failures in testing secondary containment isolation damper closure time (over 15 CRs from 1997 to 1999);
- Reactor building exhaust air profilers becoming increasingly dirty since plant startup, reducing air flow capacity by 40%, causing fan trips, surveillance problems, and building temperature problems (CR 56982 for both Unit 1 & 2), with corrective action still pending (CR 98-0078 and 98-0631, 2/27/98)
- Repetitive main steam containment isolation valve leakage rate failures with corrective action still being pursued (CR 97-0781, CR 98-1538, CR 92338, CR 187209, CR 188102, CR 192005)
- Repetitive feedwater containment isolation valve leakage rate failures with corrective action still being pursued (CR97-0866, CR 98-1285, CR 92721);
- Repetitive bolt torquing issues (CR 95-0369, CR 97-1335, CR 98-2612, CR 188046); and
- TIP ball valve controls not designed or qualified for nuclear safety-related service (CR 97-4106 and CR 216983, 11/23/99).

b.5 Root Cause Evaluations

In conjunction with the corrective action program and problem identification review, the NRC inspection team reviewed the licensee response and root cause analysis for ten significance level 1 Condition Reports (CR) issued in 1999. In general, the problem identification, corrective action, extent of condition and action to prevent recurrence were acceptable. However, for the two CRs discussed below, the team found the timeliness, action to prevent recurrence, the addressing of all causal factors and extent of condition review to be less than adequate.

- Licensee Event Report LER 50-388/99-001-00 identified that the main steam isolation valve (MSIV) failed to meet Technical Specification 3.6.1.3 allowable leakage limits. Condition report CR 92338 was issued to address that problem. The NRC inspection team found that the CR identified the most probable cause (void in the main poppet seat) and not necessarily the root causes of failure for valve HV241F022D. An additional observation had been made in the CR that the valve stroke was observed to be jerky. Though it was implied that the jerky valve stroke may have contributed to the valve leakage problem, no related cause or corrective action was provided, nor was there any action to check the extent of condition applicability to the other MSIV's.

- Condition report CR 92921addressed the feedwater check valve failure to meet Technical Specification allowable leakage limits. The NRC inspection team observed that the root cause evaluation identified the cause of failure as soft seat wear, dirt on the valve seat and hinge pin misalignment. However, the CR did not determine the cause of, or provide any actions to prevent recurrence of, the hinge pin misalignment on the 241 F010A valve and the source of the dirt on the HV-241 F032A valve; nor were the extent of condition possibilities identified regarding potential hinge pin misalignment or dirt fouling the seat of the other feedwater check valves.

As a result of PP&L's own self-assessments, the team was informed that PP&L had designated four individuals to be dedicated root cause specialists. At least one of these individuals will be assigned to guide each root cause team in the evaluation techniques.

b.6 Condition Report Trend Identification, Analysis and Reporting

The performance trending and monitoring associated with the corrective action program is controlled by procedure OES-QA-001, "Event Trending". Recurrent problems identified through the CR program should be identified promptly to reduce the risk of having a serious problem. As each CR is processed into the system it is assigned an Event Category for trending purposes.

a. Trend Condition Reports

Procedure NDAP-QA-0702 indicates the responsibility for identifying recurrent problems was shared by the Operating Experience Services (OES) screening team and the lead manager/supervisor of the group assigned the CR. During the screening meeting, when a recurrent problem is identified, the assigned significance level of the CR is required to be increased by one level from what would normally have been assigned using the guidance of NDAP-QA-0702, Attachment K. OES-QA-001 requires that adverse trends be documented on a Trend condition report.

The team noted two examples where adverse trends were identified after approximately twenty (20) or more CRs had been written and one example where the CR failed to explicitly identify the negative trend:

- On September 29, 1999, Health Physics wrote trend CR 205347. This was written after 32 CRs were written from January 1998 through September 1999 concerning radiological postings. Of these 32 CRs, 12 were written between July and September 1999 and of these 12, 7 were written in September 1999.

- On January 19, 1999, Chemistry wrote trend CR 88787. This was written after 20 CRs were written from January 1998 through January 1999 concerning the use and control of chemicals. The only CR documented, as a past occurrence, on the trend CR (88787) was the most recent CR (88628) which was written on January 14, 1999.

- On July 14, 1999, An NAS audit (99-007) of the Health Physics Program, dated July 14, 1999, identified a negative trend in the area of training. The finding was entered into the CAP as CR 98351, however the CR failed to explicitly identify the finding as a negative trend. (See Section 3.b.3 of this report for details.)

The above CRs were written after several significant events had transpired, which ultimately raised the level of licensee awareness. No clear threshold exists to initiate Trend CRs and most of the trend CR are written based on the corporate memory of the staff.

b. CR Trending

Procedure OES-QA-001, Attachment B, defines 53 event categories. Although not specifically identified in the text of the attachment, the drop-down menu in the computer database also includes an entry for Trends. All of the event categories are generic and no trending is performed at the component level in the CR database. The team considered a lack of problem identification at the component level in the database as a weakness in the trending program. This item has now been identified in the SSES Corrective Action Program Improvement Plan.

The OES Third Quarter Trend Report (PLI-88544), issued December 7, 1999, was a new format and had not yet received management review during this inspection. This report provided trend information on CR generation, significance levels, corrective action closeout and a three year rolling quarterly trend of the 53 event categories identified in OES-QA-001, Attachment B. In addition, the report provided trend information on the number of CRs written on 23 systems, also in a three year rolling quarterly format. The team noted that the trend graphs did not contain any improvement goals. The report indicated that 22 trend condition reports had been issued during the first three quarters of 1999.

NAS performed internal trends to support their own audits and assessments and included both those trends identified as trend CRs by OES and also other CRs developed as a result of previous NAS audits and assessments. These trend assessments by NAS continue to identify weaknesses with the corrective action program, including ineffective corrective action and CRs being closed without the corrective action being implemented.

b.7 Operating Experience Services Condition Report Screening Meetings

The team observed three Operating Experience Services (OES) daily CR screening meetings at which the CRs from the previous day were categorized and assigned to responsible functional units. This screening process consisted of a reading of the CRs to the committee followed by classification and assignment of the CR. The team noted that the committee members, representing OES, Operations, Maintenance and ISEG, did not have the CRs to read in advance for preparation. In addition, there appeared to be no means of identifying repeat problems other than committee members' memory of prior similar CRs. The team noted that engineering was not normally represented as a screening team member. This initial screening now receives further oversight by the Management Review Team as a result of the latest revision to procedure NDAP-QA-0702, "Condition Reports".

b.8 Failure to include the Remote Shutdown Panel Components in the Maintenance Scope

In August 1998, the NRC identified that PP&L failed to include the bypass indicating system (BIS) into the scope of the maintenance rule. This resulted in a Severity Level IV violation and was documented as EEI 50-387/388/98-04-01. PP&L documented their corrective actions in PLA-4981, response to notice of violation 50-387/388-98-04-01, dated September 21, 1998. In that response PP&L indicated that they had conducted a review to identify other safety-related systems that were not included in the maintenance rule scope. During that review the remote shutdown panel transfer switches were not identified as being in the scope of the maintenance rule. On July 14, 1998, PP&L added the BIS to the scope of the Maintenance Rule and believed they were in full compliance.

On May 13, 1998, the Remote Shutdown panel (RSP) transfer switch HSS-15112A did not properly transfer control of the Instrument Gas Compressor 1B Suction Isolation Valve (HV12603) and the Shutdown Cooling Suction Isolation Valve (HV151F009) to the RSP. The switch was replaced and returned to an operable status several days later. Condition report CR 70088 was opened to identify those failures.

On October 10, 1998, CR 70088 was assigned to system engineering to determine if the failure of RSP transfer switch was a maintenance rule functional failure (MRFF). Following further evaluation (Nuclear Information Management System (NIMS) action item 17972), PP&L identified that they had not included the safety-related functions of the remote shutdown panel in the scope of the maintenance rule and therefore the failure of the RSP transfer switch did not have to be included as a MRFF. On October 18, 1998, a NIMS action item (18653) was initiated to determine how the RSP transfer switches should be classified under the maintenance rule. One year later, on October 19, 1999, PP&L determined that the transfer switches for the reactor core isolation cooling (RCIC) system on the remote shutdown panel should be included in the scope of the Maintenance Rule (CR 204660). This discrepancy was entered in PP&L's corrective action program as condition report 226475. On December 13, 1999, PP&L initiated action items in the NIMS to revise the maintenance rule basis documents to reflect the RSP functions for several other systems. The affected systems and due dates are listed below:

NIMS No.	Due Date	Issue
220210	June 2000	residual heat removal (RHR) system
220217	June 2000	containment instrument gas (CIG) system
220219	June 2000	emergency service water (ESW) system
220220	June 2000	residual heat removal service water (RHRSW)

10 CFR Part 50 Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," Criterion XVI, "Corrective Action" requires that measures shall be established to assure that conditions adverse to quality, such as deficiencies and nonconformance are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management. Contrary to this, from July 10, 1996, to January 13, 2000, PP&L had failed to include safety-related functions of the remote shutdown panel in the scope of the Maintenance Rule program. PP&L's corrective actions for the maintenance rule scope violation in August 1998, failed to identify that these RSP transfer switches were not included in the maintenance rule program scope. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the Enforcement Policy. **(NCV 05000387 & 05000388/99013-02)**

b.9 Scram Reports and Investigations

The team considered the scram reports and associated investigations to be thorough and detailed and noted cases where these investigations found precursor problems or events which if previously identified could have prevented the scram. The team reviewed the detailed corrective actions for the scram of July 2, 1998, CR 98-2267 and the ISEG investigations 5-98 and 7-98. Fourteen CRs were generated from these two ISEG investigations predominantly involving procedure changes and operator training. The team verified the corrective actions involving procedural changes and concluded the corrective actions were adequate.

b.10 Plant Walkdowns

The inspectors performed walkdowns of both Unit control rooms, accompanied plant operators on rounds in the Unit 1 and 2 reactor and turbine buildings, and walked down selected individual systems. During these walkdowns the control room and plant operators were questioned concerning operator work-arounds. No work-around issues were found that were not being tracked in the work-arounds list.

During the walkdowns and operator rounds, no significant unidentified deficiencies were observed. Minor deficiencies were noted such as burned out light bulbs which were corrected by the operator, and an oil leak on the 1A reactor recirculation pump MG set for which the operator wrote a work request. The inspector selected 12 deficiency identification tags on various pieces of equipment and verified that work orders existed for each item.

c. Conclusions

In general, PP&L appropriately identified problems and entered them into a corrective action mechanism. Formal investigations and assessments, such as scram investigations and independent safety engineering group (ISEG) assessments, were thorough and identified plant and human performance issues beyond the immediate causes of the scram.

PP&L failed to perform a timely operability determination for the standby liquid control (SLC) system during air sparge. A non-cited violation (NCV) was issued for failure to timely inform the operating staff of a determination that concluded system inoperability.

PP&L did not identify the safety-related remote shutdown panel (RSP) transfer switch functions during their corrective action of a previous NRC violation, which identified that the bypass indication system was not in the maintenance rule scope. Failure to identify and include the safety-related functions of the RSP resulted in PP&L excluding the RSP from July 10, 1996 to January 10, 2000. An NCV was issued for inadequate corrective action.

Examples were noted of human performance, work planning, or coordination issues which should have been addressed by a condition report (CR) but were not until prompting was provided by a licensee manager, auditor or NRC staff. Other examples were identified where CR generation was not timely.

The team concluded that PP&L was not consistently meeting procedure requirements for operability screenings and determinations. This resulted in a minor violation due to failure to follow the CR procedure requirements for not promptly submitting the CR for an operability screening.

The team identified that condition report due dates were revised without approval. The maintenance data administrator estimated that approximately 12 condition report action (CRA) dates were changed per week. The practice of revising CRA due dates, without the required extension approvals is considered a minor violation. Maintenance terminated this practice in November 1999.

2 **Operating Experience Review Program** (40500)

a. Scope of Inspection

The team reviewed the PP&L efforts to identify and evaluate problems, previously identified by others, that could potentially affect the SSES operations. The goal of the team's review was to assess the effectiveness of those PP&L efforts. This review focused on problems identified through a sampling of NRC industry correspondence such as information notices and bulletins, vendor correspondence including service information letters and Part 21 notices and other reports.

b. Observations and Findings

b.1 Process Overview

PP&L's Operating Experience Review Program was controlled through station procedure NDAP-QA-0725, "Industry Event Review Program." The team's review identified that the initial processing of information is informal. Items are distributed, but not tracked for review. However, recent changes in this program require items that have clearly been identified as applicable to PP&L be entered into the condition reporting system. This positive change provides clear expectations for timeliness of actions as well as operability reviews of these issues.

b.2 Review of Operating Experience Items

The team found that PP&L's use of the industry operating experience information was not consistently effective. The team identified issues that were successfully processed using the industry experience program. Some of these issues were acoustic monitor environmental qualification (CR 97121), Laguna Verde refueling bridge brake (CR 86465), and valve breaker aux. contacts (CR 70519). However, the team also identified issues in which previous PP&L's utilization of industry operating experience in the late 1980s and early 1990s had not been completely effective. These issues had resulted in a recent unplanned automatic plant shutdown and risk significant equipment being unavailable for service.

a. Unit 2 "A" Main Transformer Neutral Bushing Failure (CR 94580)

A Unit 2 scram on June 8, 1999, (CR 97580) had been caused by the failure of a defective bushing in the "A" phase of the main transformer (LER 50-388/99-003). PP&L's initial root cause analysis, extent of condition reviews and corrective actions were good. The root cause analysis determined that the failure to adequately process the ABB letter through the Industry Event Review Program (IERP) attributed to the installation of these defective parts.

PP&L's planned corrective actions included a review of vendor information to determine if the information was included in the operating experience program. However, in November 1999, PP&L modified this action to sample vendor information already in the operating experience program to determine if the information had been processed properly. This modified extent of condition review did not address the original issue in which the service advisory letter was not entered into the operating experience program.

b. Unit 1 Reactor Core Isolation Cooling Leak Detection Failure (CR 194239)

On August 8, 1999, the Unit 1 Reactor Core Isolation Cooling (RCIC) system steam leak detection system alarmed (LER 50-387/99-004). PP&L verified that this alarm was caused by a failure of a recently installed temperature switch. The steam supply valves to the RCIC turbine were closed for approximately four hours while the switch was replaced. Analysis of the temperature switch, a safety-related component, identified a failed capacitor in the power supply caused the malfunction. Further evaluation by PP&L identified that this switch had been received in 1984 and was assigned a seven year shelf life. In 1986 a vendor notice was received that recommended upgrading the capacitor to extend the shelf life. The vendor information was processed in the operating experience program with a disposition to replace the capacitors or dispose of the temperature switch. The required actions in the operating experience document were not completed for this switch. Therefore, when this module was placed in service it failed and resulted in RCIC, a risk significant system, unexpectedly becoming inoperable.

PP&L's root cause analysis, extent of condition reviews and corrective actions were good. However, the incorporation of this operating experience information into station guidance was incomplete. The vendor manual did not contain information on the seven year shelf life. Corrective actions were not completed and the deficient temperature switch was not adequately controlled to prevent the switch from being installed into the leak detection system.

The team, as well as PP&L, concluded that the failure of the "A" main transformer neutral bushing and the RCIC leak detection temperature switch resulted, in part, because of ineffective control of these non-conforming components. The team concluded that the operating experience program weaknesses that resulted in the failures of the Unit 2 "A" main transformer neutral bushing and the Unit 1 RCIC leak detection temperature switch occurred in the late 1980s and early 1990s. However, the effects of the operating experience program deficiencies are effecting current day operation. Based on the team's review of the operating experience program, there were no planned corrective actions to select and thoroughly review a group of risk significant operating experience items prior to this inspection. Following the onsite portion of this inspection, PP&L reassessed their response to LER 50-388/99-003, and issued CR227396 to address the concern of potential non-conforming materials.

10 CFR Part 50, Appendix B, Criterion XV, requires, in part, that measures be established to control components which do not conform to requirements in order to prevent their inadvertent use or installation. Failure to properly control non-conforming components to prevent their installation is a Severity Level IV violation of 10 CFR Part 50, Appendix B, Criterion XV, and is being treated as a non-cited violation **(NCV 05000387 & 05000388/99013-03)** consistent with Appendix C of the NRC Enforcement Policy.

c. Conclusions

The present industry operating experience program relies primarily on discussions during the initial screening of new industry experience reviews. However, once the event is determined to be applicable to PP&L, the issue is processed through the condition report system to provide a more detailed review and tracking of potential concerns.

Industry events review program failures that existed in the late 1980s and early 1990s failed to remove non-conforming components. Those same components continue to challenge the plant. The failure of the Unit 2 "A" main transformer neutral bushing and the Unit 1 reactor core isolation cooling (RCIC) leak detection temperature switch resulted, in part, because of ineffective control of those non-conforming components. An NCV was issued on this failure to prevent the installation or inadvertent use of non-conforming materials, parts or components.

3 Self-Assessment Activities (40500)

a. Scope of Inspection

The team reviewed internal departmental self-assessments and quality assurance audits to assess the PP&L resolution of self-identifies concerns. The team reviewed various recommendations and findings from internal self-assessments performed by, or audits performed of, operations, maintenance, engineering, radiation protection and chemistry.

b. Observations and Findings

b.1 Corrective Action Program Self-Assessments

The team reviewed five licensee reports documenting self-assessments of the corrective action process. The Corrective Action Process Effectiveness (CAPE) Assessment Report, dated October 1999 and Susquehanna Steam Electric Station Reliability Task Team Report, PLI-88161, dated September 15, 1999, reports were especially comprehensive and described program and process weaknesses that were consistent with the observations made by the NRC inspection team. Some of these same deficiencies were also identified in 1997 and again in 1999 in the Nuclear Assessment Services (NAS) Audits (SSES Audit No. 97-080 and 99-014) of the Corrective Action Program, dated October 7, 1997, and November 11, 1999, respectively, as well as in the licensee's December 1997 Corrective Action Process Effectiveness (CAPE) Assessment Report, dated December 29, 1997, and Addendum PLI-85275, dated March 31, 1998.

The 1997 CAPE assessment report concluded that corrective actions to address problems are frequently not implemented quickly enough to prevent recurrence, that the effectiveness of corrective actions for adverse trends is not monitored and followed-up to adjust corrective actions to prevent recurrence, and that corrective actions to address adverse conditions are frequently not effective in preventing repeat incidents. The NRC made similar observations at that time in NRC Inspection Report 50-387 & 388/97-80 and again in NRC report 50-387 & 388/99-02 .

The 1999 CAPE assessment report identified that corrective actions frequently do not address or fully address the problem identified and/or the causes, that minimal administrative control over corrective action implementation contributes to corrective action timeliness issues and repeat occurrences, that no formal criteria exists to establish what is or what is not an adverse trend and that adverse trends are not being monitored to adjust corrective action.

Based on interviews of supervisory and working level personnel the NRC inspection team observed that the findings made by NAS in the 1999 Corrective Action Process Effectiveness Assessment Report remain as a weakness. These observations include: lack of knowledge and experience in performing effectiveness assessments; inadequate training in using computer tools (NIMS); unfamiliarity with trend codes; difficulty with using the new Nuclear Information Management System (NIMS) process; and, insufficient time to perform a quality evaluation. Interviewee's reported that existing trend codes do not adequately describe the situation or event and, consequently, trend codes are routinely not entered into NIMS.

b.2 Reliability Task Team

The Reliability Task Team (RTT) performed a detailed review of 6 of 42 previous events to determine common root cause/casual factors and to recommend actions to prevent their recurrence. The RTT report found ineffective implementation of the condition report (CR) program for preventing equipment failures or their recurrence and identified weak areas which included: inappropriately low CR significance level assignments;

incomplete or inadequate root cause investigations; ineffective failure analyses; corrective actions that did not address all/actual failure mechanisms; poor extent of condition across systems and components; and, poor timeliness. Additionally, the Reliability Task Team identified that with no common vision or philosophy, the licensee organization has developed a culture that is tolerant of component failures and accommodates recovery from the results of these failures.

b.3 NAS Audit of the Health Physics Program

The team reviewed NAS audit (99-007) of the Health Physics Program, dated July 14, 1999, and confirmed that condition reports (CR) were generated for each audit finding. The team reviewed the condition reports and noted that two (98351and 98354) were significance level 2 cause determination.

Condition Report 98351 was initiated because the finding was considered a negative trend and the corrective actions for CR 97-2154 (NAS Audit 97-058) were ineffective. CR 97-2154 was initiated because three newly assigned assistant foremen had not completed the training required by the Health Physics (HP) Training Matrix. CR 98351 was generated because a large number of personnel including HP foremen, assistant foremen, and Level I and II technicians had not completed the training required by the Training Matrix. Although the finding was entered into the CAP as a CR, the description of CR 98351 failed to explicitly identify the finding as a negative trend and therefore this CR was not identified as a Trend CR.

Condition report CR 98354 dealt with a discrepancy between the Nuclear Department licensing commitments in UFSAR Table 17.2-1 and the HP Program classification as a Non-Quality Assurance (QA) Program. The determination of cause was PP&L committed to Regulatory Guide 1.33, Revision 2, but the HP Program was based on Revision 0. HP committed to develop and implement a plan to address the QA classification of the HP program and revise procedures, as appropriate. The cause determination and actions to correct the conditions were appropriate.

b.4 ISEG Surveillances

The inspectors reviewed ISEG surveillances of plant operations dated November 1998 and October 1999. These reports were extensive and evaluated in detail all aspects of the conduct operations in the plant and control rooms. The reports also incorporated an appendix with separate comments from an industry peer on the surveillance team. The observations in These reports were a mix of positives and negatives including changes from prior reports. The 1998 report listed nine recommendations, and identified one instance where a condition report had not been issued in response to a mispositioned toggle switch for control power to rack in the “E” D/G breaker. CR 87812 was subsequently issued. The 1999 report contained a repeat observation that some operational problems had not been documented in condition reports (with seven examples, all related to hardware problems) and listed ten recommendations for operational improvement. The team reviewed the 1998 recommendations with ISEG and noted that while some recommendations and observations had resulted in actions and improvements as noted in the 1999 report, others had received no apparent response - none is required for such recommendations. In the 1999 report, ISEG chose to deal with this apparent lack of response by generating a total of 26 CRs addressing the details of their recommendations and forcing them into the condition report system.

The team also reviewed the ISEG surveillance of maintenance dated March 1999 and also found this report similarly through with general conclusions similar to the team's conclusion.

b.5 Functional Unit Self-Assessments

Procedure NDAP-OO-0110, "Nuclear Department Self-Assessments," required each functional unit manager to:

- Develop and implement a self-assessment plan,
- Implement improvement actions in response to the self-assessments, and
- Maintain status of their self-assessments.

The team found that most functional units managers failed to implement one or more of the three requirements identified above. Of the approximately 23 functional units identified from the Nuclear Department Organization chart (no clear definition of functional unit was included in the procedure), your staff could only produced evidence of six "Self-assessments" during the course of this inspection. Those self-assessments that had been performed showed a wide range of initiative from one functional unit to another indicating what appeared to be inconsistent management expectation for that process. Although you had identified this failure of most functional unit managers to implement self-assessments, and had included corrective actions as goals in your Decision 1999 and Decision 2000 corporate goals, you had not documented this deficiency in your corrective action program until January 4, 2000 (CR-224551). This was another example of untimely generation of a condition report.

The team reviewed 1999 Operations, Maintenance, and Nuclear Systems Engineering (NSE) functional unit self-assessments and found them acceptable. These three departments had prepared quarterly summaries of results and status of their self-assessments. In addition, NSE had appointed a self-assessment coordinator.

b.6 Corrective Action Process Improvement Plan

Following the close of this inspection, you issued your Corrective Action Process Improvement Plan, Rev. 0, dated January 15, 2000. This initiative was in response to your internal and external audits, surveillances and self-assessments of your corrective action program. This plan listed eight areas of concentration:

- Improve Quality and Effectiveness of corrective actions,
- Improve Reporting of issues and problems throughout SSES,
- Establish a Comprehensive and Credible trending program,
- Refine and Focus the Management Review Team methods to support Timely and Effective corrective actions,
- Integrate the outputs of audits, assessments self-assessments and condition reports into a single corrective action Tracking process,

- Improve Management Information from the CR database to better Understand Performance weaknesses,
- Make the corrective action process a Used and Useful tool for Line management and others,
- Implement a single corrective action process that begins with a Single Reporting Document and uses the full capability of the Nuclear Information and Management System (NIMS) software

c. Conclusions

In general, significant facility self-assessment activities produced by Nuclear Assessment Services (NAS) are thorough, detailed, and critical. ISEG surveillances and investigations were also self critical and thorough. However, deficiencies documented in self-assessments in the past has not always resulted in action to correct the identified problems. SSES initiated a multi-focus Corrective Action Program (CAP) Improvement Plan to address the deficiencies identified by internal and external identified weaknesses in the present CAP.

The failure of most functional units to implement the requirements of the functional unit self-assessment program was identified, both by the NRC team and your Decision 2000 process, as a program deficiency and entered into the correction action program.

4 Onsite and Offsite Review Committees

a. Scope of Inspection

The team reviewed selected reports and recommendations from the independent safety evaluation group and selected notes and action items from the Plant Operating Review Committee, the Susquehanna Review Committee and the Independent Safety Engineering Group to assess the effectiveness of the independent review organizations.

b. Observations and Findings

In the latest revision of the Condition Report Procedure, NDAP-QA-0702, (Revision 7), the Corrective Action Team was replaced with the Management Review Team (MRT). The responsibilities to review CRs remained unchanged but now received a higher level of management reviews. The team observed approximately six Management Review Team (MRT) meetings. The MRT reviewed new CRs for consistency, significance level, and corrective action assignment. The new procedure revision also tasked the MRT with new responsibilities which included a review of the Evaluation and Action Plans (E&APs) for Significance Level 1 and 2 CRs. The inspectors noted that certain MRT responsibilities for E&AP reviews were not well defined within the new process. Only two of eight E&APs associated with Level 2 CRs identified for MRT review since the effective date of the new procedure (December 1, 1999) had been reviewed by the end of the inspection. This deficiency was also identified in your Corrective Action Improvement Plan issued January 15, 2000.

The inspectors also observed two Plant Operations Review Committee (PORC) meeting. This process appeared to be generally thorough and effective. Presenters and committee members were well prepared to discuss the agenda items and the discussions were professional and open. PORC critically questioned proposed changes to the plant. The team reviewed PORC meeting notes and confirmed that Bypasses (Temporary Modifications) older than six months were presented to PORC to justify their continued existence.

No Susquehanna Review Committee (SRC) meetings were held during this inspection. Therefore, the team reviewed notes of recent SRC meetings and confirmed that the notes recorded a critical review of the CR program through the Condition Report Review Subcommittee (CRRS) had been performed, as required by procedure.

c. Conclusions

The plant operations review committee (PORC) and the Susquehanna review committee (SRC) demonstrated a critical, probing, and questioning attitude. Overall, implementation of the independent review organizations continue to challenge the effectiveness of the CAP. The management review team (MRT) was slow to respond to recent responsibility changes, however they effectively implemented most of the required tasks.

5 Corrective Actions for Non-Cited Violations

a. Scope of Inspection

The team reviewed the PP&L response to NRC-issued non-cited violations (NCV) to assess how items of similar concern were treated in the SSES corrective action program. The following NCVs were reviewed:

NCV 50-387/98-10-04,	"Inservice Testing Program Test Frequency Extended",
NCV 50-387/99-04-03,	"Failure to make a one hour notification for the Unit 1 Residual Heat Removal Injection Control Valve failure",
NCV 50-387/99-05-02,	"B" Emergency Diesel Generator Inoperable Due to Missing/Loose Hardware,
NCV 50-387/99-05-03,	"Safety Relief Valve Acoustic Monitor Environmental Qualification and Installation",
NCV 50-387/99-06-01,	"Reportability Determinations",
NCV 50-387/99-11-01,	"PP&L Analysis of Reactor Scram due to Main Steam Isolation Valve Failure",
NCV 50-388/99-03-01,	"Core Spray Quarterly Flow Surveillance Did Not Meet Acceptance Criteria",
NCV 50-388/99-04-01,	"Main Steam Isolation Valve (MSIV) Seat Leakage",
NCV 50-387,388/99-07-02,	"Packaging and Shipment of Radioactive Waste".

b. Observations and Findings

The above non-cited violations (NCV) had been correctly entered into your CR process. Corrective actions associated with the following CRs were acceptable, except as noted below.

NCV 50-387/99-04-03 was issued due to the inoperability of both RHR loops on February 16, 1999, which resulted from taking the “A” RHR loop out of service for maintenance when the “B” loop was rendered inoperable by the F017B loop injection valve being failed in the closed position. Corrective actions for this event were discussed in CR 90981. The root cause was determined to be inadequate troubleshooting of a problem with the loop “B” keep fill system which resulted in declaring the loop operable based on making assumptions concerning the cause of the problem rather than doing a detailed investigation. The CR contained a good extent of condition review of similar plant and industry problems. The ultimate corrective action was the development of procedure OI-AD-509 “Troubleshooting”. This procedure requires a troubleshooting plan consisting basically of a list of potential causes of a problem and the actions needed to confirm/deny each cause. The inspector considered this an appropriate and useful corrective action.

For NVCs 50-387/99-11-01 and 50-388/99-04-01, regarding failure of the main steam containment isolation valves to meet Technical Specification leakage rates, corrective actions were entered in the licensees corrective action program. However, the condition reports root cause analyses, extent of condition reviews, actions to prevent recurrence and timeliness were inadequate in that they failed to address that jerky valve stroke movement may have contributed to the valve leakage problem, no related cause or corrective action for that movement was provided, nor was there any action to check the extent of condition applicability to the other MSIV’s.

c. Conclusions

Overall, the licensee’s implementation regarding corrective actions for NCVs was acceptable. NCVs were entered into the corrective action program, as required. Corrective actions were properly implemented on closed CRs. However, in one instance, the licensee review of the main steam isolation valve (MSIV) leakage was weak regarding root cause analyses, extent of condition reviews, actions to prevent recurrence and timeliness.

6 Use of Risk Insights

a. Scope of Inspection

The team reviewed the priority assigned to corrective actions, operator work-arounds, temporary modifications, back-logged work requests and other maintenance work, open engineering items from the 50.54(f) review, the design basis document (DBD) development program and the Improved Technical Specification development programs to assess the PP&L use of risk insights.

b. Observations and Findings

b.1 Risk Ranking of Condition Reports

The team attended a presentation to the Nuclear Analysis group of Nuclear Technology by PP&L's consultant describing the development of a software program to determine the risk ranking of open condition reports. This program, if implemented as described, would permit PP&L to assign priority to those corrective actions with the highest contribution to core damage frequency risk reduction. The team considered this a positive initiative.

b.2 Extension of Risk Significant Valve Inspections (CR 98-2660)

In 1998, PP&L identified that the Unit 1 reactor water clean up (RWCU) inboard and outboard containment isolation motor-operated valves (HV-144-F001 and HV-144-F004) had reduced operating torque margin. PP&L concluded that these valves were operable, but degraded and increased the priority to complete internal valve inspections. On August 11, 1998, PP&L identified (CR 98-2660) that internal valve inspections were not completed on the Unit 1 RWCU containment isolation valves. On May 29, 1999, the same day that Unit 1 shutdown for a forced outage, PP&L extended the inspections of the RWCU valves to the next Unit 1 refueling outage. This extension did not consider any risk perspectives for extending these valve inspections.

The NRC considers the RWCU insolation valves high risk significant valves (Generic Letter 89-10, supplement 3). This is based on evaluation of the MOV data provided by the BWR Owners' Group and the results of the NRC-sponsored tests. In addition, in this case both RWCU primary containment insolation valves, in the same penetration are degraded. Therefore, if PP&L reviewed the list of condition reports actions that were being extended from a risk perspective, PP&L may have been able to more effectively reduce the operational risk.

c. Conclusion

PP&L's proposed use of risk insights to assist in prioritizing attention on risk significant condition reports could develop into a useful tool to minimize plant risk.

Although PP&L had identified decreasing margins on the high risk reactor water cleanup (RWCU) isolation valves, you extended the completion date of required internal inspections of those valves during the May 1999 forced outage at Unit 1 without reviewing the risk of extending those inspections.

V. Management Meetings

X1 Exit Meeting Summary

The preliminary inspection observations of the first week of the onsite inspection were discussed with members of PP&L management at a de-brief on December 17, 1999. An exit meeting was held with PP&L management on January 13, 2000, where the preliminary results of the inspection were discussed. PP&L acknowledged the inspection findings presented and confirmed that no proprietary information was identified. PP&L questioned the categorization of the findings but did not dispute them.

PARTIAL LIST OF PERSONS CONTACTED

Pennsylvania Power Light Company

R. Byron	Sr. Vice Present, Generation and Chief Nuclear Officer
R. Saunders	Vice President, Nuclear Site Operations
G. Jones	Vice President, Nuclear Engineering & Support
B. Shriver	General Manager, Susquehanna Steam Electric Station
G. Miller	General Manager, Nuclear Assurance
K. Chambliss	Manager, Nuclear Operations
D. Smith	Manager, Rad Protection
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G. Castleberry	Supervisor, Effluents Management
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R. Saccone	Manager, Nuclear Modifications
M. Simpson	Manager, Nuclear Technology
T. Harpster	Manager, Nuclear Licensing
R. Pagodin	Manager, Nuclear Systems Engineering
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J. Miltenberger	Manager, Independent Safety Engineering Group
D. Filchner	Senior Engineer, Nuclear Licensing, Inspection Lead Contact
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E. Miller	Senior Engineer, Operations Engineering, Inspection Operations Contact
L. Mahasky	Resource Supervisor, Maintenance Support, Inspection Maintenance Contact
J. Hill	Supervisor, Radiological Operations, Inspection Health Physics Contact

U. S. Nuclear Regulatory Commission

W. Ruland	Chief, Electrical Engineering Branch, Division of Reactor Safety
S. Hansell	Senior Resident Inspector
J. Richmond	Resident Inspector

INSPECTION PROCEDURES USED

IP40500	Effectiveness of Licensee Process to Identify, Resolve, and Prevent Problems

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

NCV	50-387/388/99-13-01	Delayed Operability Determination for SLC Air Sparge
NCV	50-387/388/99-13-02	Inadequate Corrective Action Regarding Maintenance Rule Scope
NCV	50-387/388/99-13-03	Non-Conforming Material Extent of Condition

LIST OF ACRONYMS USED

AOT	Allowable Outage Time
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CR	Condition Report
CRA	Condition Report Action
CRRS	Condition Report Review Subcommittee
DBA	Design Basis Accident
DBD	Design Basis Document
E&AP	Evaluation and Action Plan
EDG	Emergency Diesel Generator
EPRI	Electric Power Research Institute
ESW	Emergency Service Water
FME	Foreign Material Exclusion
GL	Generic Letter
HP	Health Physics
HPCI	High Pressure Coolant Injection
IERP	Industry Event Review Program
INPO	Institute of Nuclear Power Operations
IRM	Intermediate Range Monitor
ISEG	Independent Safety Engineering Group
IST	In-service Testing
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MG	Motor Generator
MRT	Management Review Team
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NDAP	Nuclear Department Administrative Procedure
OES	Operating Experience Services
NRC	Nuclear Regulatory Commission
QA	Quality Assurance
PCIV	Primary Containment Isolation Valve
PCPR	Plant Component Problem Report
PORC	Plant Operations Review Committee
PP&L	Pennsylvania Power & Light Company
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RSP	Remote Shutdown Panel
RTT	Reliability Task Team
RWCU	Reactor Water Clean-up
SAL	Service Adversary Letter
SCFM	Standard Cubic Feet per Minute
SLC	Standby Liquid Control
SRC	Susquehanna Review Committee
SSES	Susquehanna Steam Electric Station
TS	Technical Specification

UFSAR	Updated Final Safety Analysis Report
USQ	Unreviewed Safety Question