U. S. NUCLEAR REGULATORY COMMISSION

REGION I

License Nos.	DPR-66, NPF-73
Report Nos.	50-334/98-01, 50-412/98-01
Docket Nos.	50-334, 50-412
Licensee:	Duquesne Light Company (DLC) Post Office Box 4 Shippingport, PA 15077
Facility:	Beaver Valley Power Station, Units 1 and 2
Inspection Period:	February 8, 1998 through March 21, 1998
Inspectors:	D. Kern, Senior Resident Inspector F. Lyon, Resident Inspector G. Dentel, Resident Inspector J. Furia, Senior Radiation Specialist L. Briggs, Operations Engineer L. Peluso, Radiation Physicist
Approved by:	M. Evans, Chief Reactor Projects Branch 7

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EXECUTIVE SUMMARY

Beaver Valley Power Station, Units 1 & 2
NRC Inspection Report 50-334/98-01 & 50-412/98-01

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection. In addition, it includes the results of announced inspections by regional inspectors in the areas of health physics and technical specifications, and an in-office review of an unresolved item in the area of health physics.

Operations

- Good operator attention to reactor vessel level and supporting parameters during depressurization of the reactor coolant system (RCS) resulted in quick identification and appropriate venting of a nitrogen gas bubble in the reactor vessel. (Section O1.2)

- Poor procedure quality and failure of operators to identify the procedural deficiencies resulted in an unexpected feedwater isolation valve closure while feeding the steam generators to wet layup conditions. (Section O4.1)

- Following the Unit 1 forced shutdown in January 1998, senior management acknowledged the broad scope and significance of technical specification (TS) surveillance testing problems. Both the NRC inspectors and a multi-faceted self-assessment independently determined that long standing problems including poor TS quality, a non-conservative philosophy regarding TS interpretation, and broad knowledge deficiencies regarding TS were the primary causal factors. Combined, these deficiencies have necessitated a significant amount of reactive work to correct problems at the station. Management struggled to define the scope, detail, and implementation schedule for corrective actions. Senior management stated their intent to complete appropriate corrective actions prior to restart of either unit. (Section O8.1)

Maintenance

- Implementation of the preventive maintenance (PM) program was adequate. The number of delinquent PM tasks has been significantly reduced over the past ten months. PMs were being performed as required, and PM deferrals were adequately justified. (Section M1.2)

- Routine maintenance and surveillance testing was generally performed safely and in accordance with procedures. System engineering and supervisor oversight was good. Foreign material exclusion controls were properly instituted and followed. The decision to repair all three Unit 2 PORVs to eliminate minor leakage prior to unit restart demonstrated appropriate regard to maintaining plant material condition. However, the 18 month overhaul of the Unit 2 2-2 emergency diesel generator (EDG) was ineffectively planned. Conflicts with the clearance, multiple conflicting tasks working concurrently, and other scheduling problems resulted in extended outage time for the EDG and additional risk of injury for workers. In addition, failure to plan the post maintenance testing prior to beginning PORVs repairs delayed the system restoration. (Section M1.3, M1.4, M1.5, and M1.6)

- Plant material condition and housekeeping were adequate. Control of transient equipment was good. Most equipment deficiencies were identified by Material Deficiency Tags; however, the inspectors noted an error rate in tag control of about 1/3, based on a random sample of 64 tags in the field. The high error rate had the potential to mask equipment deficiencies or adverse trends. The corrective and general maintenance backlog was properly prioritized. Minor maintenance was properly categorized. Maintenance backlogs on individual systems were typically low, though some outliers including the Unit 1 river water system and the fire protection and heat tracing systems at both units, were noted. Systems were properly monitored in accordance with the Maintenance Rule. (Section M2.1)

- The Maintenance organization was adequately staffed to support the plant. However, maintenance planning and scheduling processes were not mature and implementation of an action plan to improve work management had begun. The inability to plan and work maintenance activities according to schedule contributed to the need for additional resources, increased operator burden, and increased equipment out-of-service time. Deficiencies in work package quality were not effectively addressed. Fix-It-Now (FIN) team work was properly categorized and the FIN program was effective in meeting its goals. The poor planning and control of operational post maintenance testing (PMT) created an unnecessary operational burden on the control room staff, as well as the potential to restore equipment to service with inadequate PMT. (Section M6)

- The TS surveillance review team conducted a thorough and detailed review of the TS surveillance requirements and associated surveillance procedures to ensure that surveillance requirements were satisfied. Licensee actions to identify and resolve problems were comprehensive and technically correct. The full TS surveillance review team project was not implemented in a timely manner. Untimely implementation and a larger than anticipated problem resulted in the licensee requesting a commitment date extension from the NRC. Independent evaluation of the surveillance review team's activities did not identify any discrepancies in their program or its implementation. (Section M8.1)

Engineering

- The licensee recognized a TS deficiency regarding degraded voltage relay setpoints in 1993 and administratively controlled the setpoints through revisions to the maintenance surveillance procedures. The procedure revisions were inadequate and a TS amendment request to change the relay setpoints had not been submitted. The failure to adequately address a known TS deficiency in a timely manner was a Violation. Two other examples of failures to address known TS deficiencies in a timely manner contributed to LERs in the last year. (Section E1.1)

- The TS surveillance review team identified that the Unit 2 emergency diesel generator ground switch was not tested as required by TS. This was attributed to inadequate implementation of TS requirements into surveillance procedures. (Section E1.2)

- Engineers failed to fully evaluate all potential failure modes prior to installation of a modification to the Unit 2 emergency diesel generator (EDG) ground overcurrent trip isolation feature which was an example of inadequate design control and a violation. Specifically, the failure mode analysis for this design change was too narrowly focused in that failures of the quality assurance category 2 ground switch and resistor were not fully evaluated. The failure mode analysis also did not identify or evaluate an additional failure mode which had the potential to damage the EDG during surveillance testing if a fault occurred on the 4 kV line. (Section E1.2)

Plant Support

- The programs for internal and external dosimetry and respiratory protection were effectively implemented. Control of radiological work, especially in the pressurizer cubicle at Unit 2, was also effective. (Section R1)

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Summary of Plant Status

Unit 1 remained in Mode 5 (cold shutdown) in a forced outage throughout the inspection period. The unit remained shut down to resolve several Technical Specification Surveillance Requirement (TSSR) compliance issues. One major issue required modification to the nitrogen supply subsystem for the pressurizer power operated relief valves (PORVs) and an exigent Technical Specification amendment to allow PORV testing within TS requirements (applicable to both units).

Unit 2 remained in Mode 5 (cold shutdown) in a forced outage throughout the inspection period. The unit remained shut down to resolve several TSSR compliance issues. Additional work included completion of repairs to station battery 2-1 and repairs to all three pressurizer PORVs due to leaks.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. Inspectors noted a good focus on shutdown safety over the period. The shutdown safety function/equipment status sheet was reviewed at the beginning of the daily supervisors' meetings and at each shift turnover briefing. Changes in safety function status (reactor coolant system (RCS) core cooling, reactivity control, electrical power, spent fuel pool cooling, and boration inventory) were discussed and limitations due to ongoing or planned work and train priority were highlighted. Operators displayed a good questioning attitude when evaluating the impact of clearances and work on shutdown safety and TS compliance.

O1.2 Reactor Vessel Venting

a. Inspection Scope (71707)

The inspectors reviewed the operators' attention to control room parameters during routine control room tours.

b. Observations and Findings

On February 24, Unit 2 operators noted a slight decrease in the reactor vessel level indicating system and an increase in volume control tank and pressurizer levels during depressurization of the RCS. The operators promptly identified the conditions, and the senior reactor operators evaluated appropriate corrective actions. The cause of the level changes was determined to be nitrogen gas coming out of solution and creating a gas bubble in the reactor vessel. Operations management provided support in the evaluation to determine appropriate venting criteria. The reactor vessel was vented and parameters returned to expected values. The inspectors noted continued operator awareness of the level parameters and appropriate logging of the parameters during subsequent reactor head venting which occurred approximately every two days.

c. Conclusions

Good operator attention to reactor vessel level and supporting parameters during depressurization of the RCS resulted in quick identification and appropriate venting of a nitrogen gas bubble in the reactor vessel.

O4 Operator Knowledge and Performance

O4.1 Feedwater Isolation during Wet Layup of Steam Generators

a. Inspection Scope (71707)

The inspectors reviewed the operation staff's response to an unexpected Unit 2 feedwater isolation. The inspectors interviewed the operators and shift technical advisors, and reviewed operator logs. Also, procedure 2OM-24.4.I, "Feeding Steam Generators at Low Pressure and Little or no Steam Flow," Rev. 12, was reviewed.

b. Observations and Findings

On March 16, while attempting to raise the steam generator (SG) levels to wet layup condition, the feedwater isolation valves (FWIVs) unexpectedly closed due to high SG level. The operators believed that the procedure (2OM-24.4.I) blocked the feedwater isolation signal by deenergizing the FWIV 480VAC power supplies. However, the 125 VDC power supply to the solenoid operated valves that perform the auto-closure function for the FWIVs, was not deenergized. The operators reset the feedwater isolation signal, opened the FWIVs, and completed the wet layup of the steam generators.

After the isolation, operators identified the following procedural weaknesses: 1) the procedure failed to identify the 125 VDC power supply; 2) the procedure did not return the 480VAC power supply to normal system alignment, but the procedure had previously been reviewed to verify that it restored equipment to normal alignment; and 3) the Operating Manual (OM) procedures did not receive validation prior to approval. The unexpected closure and procedural weaknesses were captured in Condition Report 980506 and corrective actions include upgrading the procedure. The inspectors determined that the procedural weaknesses combined with the failure of operators to previously identify and correct the weaknesses directly led to the FWIV closure. The inspectors reviewed the reportability determination and concluded that operators appropriately determined that the event was not reportable. The procedure recognized the potential for actuating the FWIV signal; however, it did not adequately establish conditions to prevent FWIV closure.

The failure to establish an adequate procedure to raise steam generator level to wet layup conditions without causing an unnecessary feedwater isolation was a violation of TS 6.8.1.a. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy **(NCV 50-412/98-01-01)**.

c. Conclusions

Poor procedure quality and failure of operators to identify the procedural deficiencies resulted in an unexpected feedwater isolation valve closure while feeding the steam generators to wet layup conditions.

O8 Miscellaneous Operations Issue

O8.1 (Update) EA 50-334(412)/97-255-01013) Technical Specification (TS) Surveillance Program Deficiencies

a. Inspection Scope (71707, 92901, 92902, 92903)

The January 31, 1998, Unit 1 forced shutdown highlighted the continued presence of TS surveillance testing program deficiencies. During interviews with NRC inspectors, senior management stated their intent to determine the scope of the problem and implement appropriate corrective actions prior to restarting either unit. The inspectors reviewed license basis documents, reviewed licensee causal assessments, and interviewed personnel to evaluate licensee actions to assure TS requirements were properly implemented.

b. Observations and Findings

The Plant Manager met with the inspectors in early February to discuss what actions the licensee planned to implement prior to unit restart, to provide assurance that TS surveillance requirements were properly implemented. Based on the cause of the recent Unit 1 shutdown, station management recognized that methods used when performing some of the earlier test program reviews may have been incomplete. Prior to late 1997, the station-wide philosophy regarding compliance with TS requirements had often permitted too much leeway regarding interpretation of TSs. The station manager identified three specific areas for reevaluation; (1) Unit 1 NRC Generic Letter (GL) 96-01 testing, (2) Units 1&2 Emergency Core Cooling System TS required testing, and (3) Units 1&2 Electrical Distribution System TS required testing. Additional reviews would be considered during evaluation of several condition reports recently submitted regarding TS surveillance testing issues.

The inspectors noted that the large number of TS surveillance testing issues identified during the past two months and the difficulty the licensee experienced in evaluating the issue which resulted in the Unit 1 forced shutdown, indicated TS knowledge deficiencies existed throughout the licensee organization. Several additional factors, including poorly written TSs and implementing procedures, were evident. The inspectors questioned whether the licensee's planned actions were sufficient to provide assurance that the units were operated and tested as required by the TSs. The Plant Manager stated that additional actions would be considered if warranted. The following week a more detailed TS Surveillance Testing Compliance Oversight (TSSTCO) project was established.

The inspectors met with the TSSTCO project manager and reviewed project status. The project centered on five self assessments of previously completed or ongoing activities including the following:

- Unit 2 electrical distribution system safety system functional evaluation (SSFE) completed in 1997,
- all licensee event reports (LERs) and NRC violations (NOVs) issued from mid-1996 through present,
- TS surveillance testing review team findings (see Section M8.1),
- Updated Final Safety Analysis Report (UFSAR) validation project, and
- NRC GL 96-01 test program evaluations.

The self assessments were performed using a more stringent philosophy regarding TS compliance. Related condition reports issued over the past two months were also reviewed in the aggregate. Training was developed and conducted for all licensed operators based on the lessons learned from the self assessments. Independent industry consultants also performed a broad oversight review of the collective significance of the TS surveillance testing issues. Based on interviews and independent evaluation of selected issues from the licensee self assessments, the inspectors determined that the licensee assessment of the TS surveillance program deficiencies was detailed, causal assessment was adequate and initial corrective actions were properly implemented.

The TSSTCO project manager effectively presented a project status update to the Nuclear Safety Review Board in early March, noting that several of the self assessments and corrective actions were still in progress. Self assessments and corrective actions continued through the end of the inspection period. The inspectors independently determined that long-standing problems, including poor TS quality, a non-conservative philosophy regarding TS interpretation, and broad knowledge deficiencies regarding TSs were primary causal factors behind the current TS surveillance program issues. Combined, these deficiencies resulted in a significant amount of reactive work to correct problems at the station. A large procedure change backlog was a contributing factor. Licensee evaluation of the issue began to develop similar detailed findings as the report period ended.

Numerous corrective actions were initiated to provide assurance that the station would be operated in accordance with TS requirements. The majority of approximately 80 TS interpretations were canceled and the remainder were withdrawn from the control room for further evaluation. The licensee also committed to upgrade both units to the improved standard TS following completion of the UFSAR validation project in 1999. A training plan was under development to upgrade station-wide knowledge of TS. The inspectors noted that licensee management had difficulty maintaining integrated oversight for the numerous corrective actions. Management acknowledged that several of the corrective action elements required further development and that an overall implementation schedule had not yet been developed. Senior management reaffirmed the their intent to verify the station was in compliance with TSs and address the root causes to preclude recurrence prior to unit restart.

c. Conclusions

Following the Unit 1 forced shutdown in January 1998, senior management acknowledged the broad scope and significance of TS surveillance testing problems. Both the NRC inspectors and a multi-faceted licensee self-assessment independently determined that long-standing problems including poor TS quality, a non-conservative philosophy regarding TS interpretation, and broad knowledge deficiencies regarding TSs were the primary causal factors. Combined, these deficiencies necessitated a significant amount of reactive work to correct problems at the station. Management struggled to define the scope, detail, and implementation schedule for corrective actions. Senior management stated their intent to complete appropriate corrective actions prior to restart of either unit.

O8.2 Offsite Review Committee Meetings (71707)

The inspectors attended portions of the Maintenance and Engineering Subcommittee, Operating Experience Subcommittee, and Offsite Review Committee meetings on March 3 and 4. Committee members expressed concern with the number of issues being identified at the site and the potential impact on plant restart. Through discussion with DLC management, inspectors verified that the concern was with identifying all of the issues that were reasonable to find and was not mistaken as a recommendation to restart the units hastily. The President, Generation Group, reiterated to the committee and to DLC management that safety was paramount and that the units would not be restarted until there was adequate assurance that they would be operated in compliance with license requirements. The inspectors assessed that his statements were appropriate to ensure that a mixed message was not being given to the site.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (62707)

The inspectors reviewed several maintenance program elements to verify that activities were properly planned and scheduled, conducted in a safe and controlled manner, and conducted in accordance with approved procedures. The backlog of both corrective maintenance and preventive maintenance activities was reviewed on a sampling basis to verify that all identified plant equipment deficiencies were properly evaluated and prioritized. Interviews were conducted with personnel at all levels of the organization, and observations were made of several ongoing maintenance activities.

M1.2 Preventive Maintenance Program

a. Inspection Scope (62707)

The inspectors reviewed the adequacy of the preventive maintenance (PM) program, including the backlog, PM deferrals, and the status of the PM Optimization Program.

b. Observations and Findings

DLC added two PM Coordinators to the Work Management organization in August 1997. The inspectors reviewed the governing instruction for the PM program, NPDAP 8.31, "PM Program," Rev. 2 and discussed program implementation with a PM Coordinator. DLC has not yet completed baselining the PM schedule, but it appeared that PM tasks were properly scheduled and controlled. The coordinators were providing PM tasks to the schedulers about three months ahead of the 12-week schedule process. PM optimization was in progress at the rate of about three site systems per month by the system engineering staff. Seven systems were complete, and PM rescheduling/modification justification forms had been provided to the coordinators. DLC intended to complete review of all critical systems by the end of 1998, and complete the program by April 1, 1999.

The inspectors noted that delinquent PM tasks (PMs beyond their established duration by more that the 25% grace period) had been reduced from 53 in May 1997 to zero in November 1997. There had been one delinquent PM since then, which was documented on Condition Report 980320. Deferred PMs were also trending less than 3 per week. The inspectors reviewed 10 PM deferrals and assessed that they were adequately justified. The inspectors also reviewed the PM feedback forms submitted by craftsmen after completion of the PM tasks. Almost all of the feedback was positive; few substantive comments were noted.

c. Conclusions

Licensee implementation of the PM program was adequate. The number of delinquent PM tasks has been significantly reduced over the past ten months. PMs were performed as required, and PM deferrals were adequately justified.

M1.3 Routine Maintenance Observations (62707)

The inspectors observed portions of selected maintenance activities on important systems and components. The activities observed and reviewed are listed below.

- MWR 70130 Inspect MOV-1QS-100A and obtain MOVATS data
- MWR 60526 General Inspection of Diesel Generator 2-2 Internals

The system engineer visited the job site to review the work in progress and discuss it with the technicians. The activities observed and reviewed were performed safely and in accordance with proper procedures. Inspectors noted that an appropriate level of supervisory attention was given to the work based on its priority and difficulty.

M1.4 Routine Surveillance Observations (61726)

The inspectors observed portions of selected surveillance tests. Tests reviewed and observed by the inspectors are listed below.

- 1OST-24.8 "Motor Driven Auxiliary Feed Pumps Check Valves and Flow Test," Rev.7
- 1OST-36.22A "DG No.1 Simulated Undervoltage Start Signal," Rev.0
- 1OST-36.1 "DG No.1 Monthly Test," Rev.19

The surveillance testing was performed safely and in accordance with proper procedures. Pre-evolution briefings were thorough and covered precautions and limitations, contingencies, and communications. Input was provided by the system and IST engineers as appropriate. The inspectors noted that an appropriate level of supervisory attention was given to the testing, depending on its sensitivity.

M1.5 Unit 2 Emergency Diesel Generator Overhaul

a. Inspection Scope (62707)

The inspectors observed portions of the Unit 2 Emergency Diesel Generator (EDG) overhaul. The following procedures and work instructions were reviewed:

- 2ICP-36-LS10(11)-2 "Diesel Generator 2-2 Lube Oil Level Switch Calibration," Rev. 1 and Rev. 2
- 2MSP 36.20-M "General Inspection of Diesel Generator 2-2 Internals," Rev. 1

b. Observations and Findings

After determining that a TS amendment was needed for the Unit 2 pressurizer PORV post maintenance testing (further discussed in Section M1.6), and that would result in extension of the Unit 2 shutdown, licensee management expanded the scope of the forced outage. Outage management scheduled additional work activities, including items scheduled for the next Unit 2 refueling outage, such as the 18 month overhaul of the 2-2 EDG.

During observations of the work activities, the inspectors noted multiple ongoing work activities that appeared to conflict with each other. The inspectors observed worker safety issues that resulted from the multiple tasks including fuel oil dripping down on workers and reliance on one-way verbal communication during EDG shaft rotations. The inspectors observed that good foreign material exclusion (FME) controls were implemented.

After several days, the inspector noted that the EDG work activities were behind schedule and questioned work planning and outage management concerning the planning for the EDG work. Initial delays were due to limited knowledge level of the construction workers in building the scaffolding for the EDG work. The clearance established for the EDG work resulted in an inability to perform an Instrumentation and Controls (I&C) maintenance surveillance due to removal of a DC power source. This I&C surveillance is normally scheduled during the 18 month overhaul. The maintenance supervisor had already noted the problems with the scaffolding and clearance, and immediate corrective actions had been taken. Further discussion with outage management revealed that a detailed schedule for the EDG outage had not been prepared. Normally, major work activities conducted at the site have a detailed schedule. After discussions, the outage manager agreed that a more detailed schedule would be appropriate and one was constructed.

The inspectors concluded that the lack of detailed planning and preparation for the 18 month overhaul of the 2-2 EDG resulted in additional outage time and additional risk of injury for workers. The original schedule for the outage was approximately 10 days and the actual outage time was 14 days.

c. Conclusions

The 18 month overhaul of the Unit 2 2-2 EDG was ineffectively planned. Conflicts with the clearance, multiple conflicting tasks working concurrently, and other scheduling problems resulted in extended outage time for the EDG and an additional risk of injury for workers. Good FME controls were instituted and followed.

M1.6 Unit 2 Pressurizer Power Operated Relief Valves (PORVs) Repair

a. Inspection Scope (62707, 71750)

The inspectors observed the planning and performance of maintenance associated with the repair of the Unit 2 PORVs. During the performance of work, the following procedures were used:

- 2CMP-6RCS-PORV-1M "Repair of Pressurizer Power Operated Relief Valves," Rev. 1
- MWR 070114 "Pressurizer Power Operated Relief Valve Repair"

b. Observations and Findings

The licensee decided to repair all three Unit 2 Pressurizer PORVs after observing increased leakage through the PORVs in service for low temperature overpressure protection. Based on temperature measurements and observations during the past refueling cycle, the system engineer observed minor leakage through the PORVs (a maximum of 80 gallons per day). The inspectors noted thorough tracking and trending of the PORV conditions by the system engineer.

The repair consisted of replacement of the pilot valves with improved seating material and repair/replacement of the PORVs. The inspectors noted good initial planning with multi-discipline input and in-depth questioning. However, the post maintenance testing (PMT) was not planned until midway through the actual work. The inspectors observed good vendor and supervisor involvement, and FME controls during the repair activities. The inspectors identified and informed the work crew of some minor deficiencies in their radiological work practices. The inspectors' observations were promptly addressed. The resolution of material discrepancies noted in the repair were successfully handled through vendor and onsite engineering.

The PMT was planned under a temporary procedure, 2TOP 98-02. The Onsite Safety Committee determined that the PMT could not be performed due to conflicts with Technical Specification requirements. TS 3.4.9.3 requires that the overpressure protection system shall be operable with either two PORVs available or the RCS depressurized and an RCS vent established. The PMT required pressurization of the RCS and stroking of the valve. This was in direct conflict with the TS requirements. The licensee determined that licensing action would be required. During reviews, operators noted other instances where the PMT could be in direct conflict with TS requirements. On March 16, the licensee submitted an exigent TS amendment request to allow PMT under administrative controls to bring equipment back to service.

c. Conclusions

The decision to repair all three Unit 2 PORVs to eliminate minor leakage prior to unit restart demonstrated appropriate regard to maintaining plant material condition. The PORV removal and inspection activities were characterized by good initial planning, vendor involvement, and supervisory oversight. However, post maintenance testing was not planned until after the work began and conflicted with Technical Specifications. Failure to plan the PMT prior to beginning repairs delayed the system restoration.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Housekeeping and Material Deficiency Tag Issues

a. Inspection Scope (62707)

Inspectors made a number of plant tours and conducted several partial walkdowns of systems to assess the material condition of the plant. This included a review of identified maintenance deficiencies to verify that the condition of plant equipment was acceptable to support safe operation. Inspectors also verified that identified deficiencies were being prioritized and corrected commensurate with their safety significance.

b. Observations and Findings

During plant tours and walkdowns of systems, the inspectors noted some minor deficiencies, such as valve packing leaks, oil leaks, loose or unattached lagging, and inoperative lighting. Most deficiencies were captured on deficiency tags, but some minor deficiencies were not marked by deficiency tags or captured in the maintenance database against the component. For example, packing leaks were noted on valves TV-1CCR-121-1, TV-1CCR-137, and a flange downstream of 2CHS-578 (with drip bag installed); an oil leak was noted on CH-P-1B motor; small oil leaks were noted on the 1VS-AC-9 fan motor, GW-C-1B, and MOV-1HY-101B; a valve label had fallen off 1PC-118; area lights were burnt out behind 1VS-AC-8, over BR-P-2A, and in the Unit 1 west cable vault lower passageway; and smoke detectors in the Unit 1 west and east cable vaults and the control room were marked "bad," with no accompanying explanation. These discrepancies were referred to the nuclear shift supervisor for evaluation. Overall, plant housekeeping was considered to be adequate.

Control of transient equipment such as carts, scaffolds, and test equipment was good. One unrestrained ladder that was not in use was noted outside the boron recovery evaporator cubicle. This was referred to the radiological controls shift supervisor for resolution.

The management expectation was that Material Deficiency Tags would be used to identify equipment deficiencies, with the exceptions of containment or areas where radiological or personnel safety concerns took precedence. Most equipment deficiencies were identified by Material Deficiency Tags; however, some discrepancies were noted. The inspectors selected 64 tags during plant tours to verify their tracking status. The tags originated from 1995 to date. Forty-two tags were in the work control process and work was in progress (about 66%). The work for 11 tags was complete, but the tags were still hanging in the field (about 17%). Eleven tags were not entered in the work control system (about 17%). These indicated an error rate of about 1/3 in the deficiency tag system. The high error rate had the potential to mask equipment deficiencies or adverse trends. The inspectors discussed the issue with Maintenance management. The licensee generated Condition Reports 980474 and 980475 to document further evaluation under the corrective action program.

The non-outage corrective and general maintenance backlog was 1011 items, as of March 8. The trend had been downward from 1221 items in November to 929 in January, but had climbed slowly since the beginning of the dual unit forced outages. Management anticipated reversing the trend when the units were returned to service, but planned to review the data more closely in the summer to decide whether additional focused effort would be necessary to meet a year-end backlog goal of 800 items. The inspectors reviewed the corrective and general maintenance backlog and assessed that it was properly prioritized. The inspectors reviewed the backlog of work for selected safety-related systems that were important to mitigating core damage in accordance with the probabilistic risk assessment. For Unit 1, the river water system with 25 maintenance work requests (MWRs), the steam generator feedwater system (including auxiliary feedwater) with 13 MWRs, and the 4kV station service system with 12, had the highest backlogs among the top risk-important systems. For Unit 2, the service water system with 13 MWRs had the highest backlog among risk-important systems. The inspectors reviewed the System Engineering System Status Report, 4th Quarter 1997, and assessed that systems were being properly monitored in accordance with the Maintenance Rule.

In general, backlogs of priorities-3 and 4 MWRs for non-risk-important individual systems were low (typically less than twelve). Some outliers at Unit 1 were water treating systems with 44 MWRs and boron recovery and primary makeup systems with 28. The inspectors also noted large backlogs in the fire protection system (8 priority-3 and 72 priority-4 MWRs) and miscellaneous safety-related instrumentation system (3 priority-3 and 59 priority-4 MWRs), the majority of which were heat tracing system deficiencies. At Unit 2, outliers included the condensate polishing system with 22 MWRs and the auxiliary boiler system with 18. The Unit 2 fire protection system and electric heat tracing system also had large backlogs (31 and 16 MWRs, respectively).

In addition, the inspectors reviewed the non-outage minor maintenance backlog. The minor maintenance backlog was 494 items (as of March 8) and had trended at about 500 since November. The backlog appeared to be properly categorized in accordance with Nuclear Power Division Administrative Procedure (NPDAP) 7.15, "Initiation of a Work Request."

c. <u>Conclusions</u>

Plant material condition and housekeeping were adequate. Control of transient equipment was good. Most equipment deficiencies were identified by Material Deficiency Tags; however, the inspectors noted an error rate in tag control of about 1/3, based on a random sample of 64 tags in the field. The high error rate had the potential to mask equipment deficiencies or adverse trends. The licensee documented the observation in the corrective action system for additional evaluation. The corrective and general maintenance backlog was properly prioritized. Minor maintenance appeared to be properly categorized. Maintenance backlogs on individual systems were typically low, though some outliers were noted, for example, the Unit 1 river water system and the fire protection and heat tracing systems at both units. Systems were properly monitored in accordance with the Maintenance Rule.

M6 Maintenance Organization and Administration

a. Inspection Scope (62707)

The inspectors assessed the ability of the Maintenance organization to support the plant. The organization reported to the General Manager, Maintenance Programs Unit (MPU), who reported to the Plant Manager. The MPU was divided into the Mechanical, Electrical, I&C (Instrument and Controls), Fix-It-Now (FiN) Team, Maintenance Support (such as procedures, corrective action program, self-assessment, and performance indicators), and Work Management Sections (planning and on-line scheduling).

b. Observations and Findings

The maintenance organization was adequately staffed to support the plant. Maintenance staff were working on average about 15 hours of overtime per week. There was not a dependence on excessive overtime to accomplish work nor on contractor support, except in the Work Management Section, where 18 of 45 positions were filled by contractor personnel. The Work Management Section has been evolving since June 1997, when the licensee implemented a Maintenance Improvement Plan to improve planning, scheduling, and work control processes; otherwise, the organization has been relatively stable.

The inspectors noted that stabilizing the 12-week work management process, enforcing schedule discipline, and reducing the corrective maintenance backlog were among the top concerns of the Maintenance organization at all levels. Some other concerns mentioned were inaccuracies in the Material Equipment List (MEL), parts support, quality of work packages, and a weak Maintenance database management software program. The inspectors noted that most of the concerns were related.

Inaccuracies in the MEL were a frustration for planners, particularly the contractor staff who typically had a lot of experience in planning, but did not have as much specific experience at Beaver Valley as the DLC employees. Lack of trust in the MEL forced the planners to spend more time in the field verifying parts information. Nevertheless, craftsmen frequently mentioned incorrect parts, insufficient quantity, or incorrect revision as deficiencies in the work packages.

The inspectors noted that a contributing factor in parts problems was the short lead time provided to the Nuclear Procurement Department (NPD). According to NPDAP 7.12, "Non-Outage Planning, Scheduling, and Risk Assessment," Rev.4, parts should be identified and ordered in weeks 9 through 7 before the work execution week; however, NPD performance indicators for 1997 showed about 45% of parts were identified after week 7. The impact of emergent work and failure to control work scope were also contributing factors. Maintenance management did not have a current performance indicator to measure those variables, but one indicator from 1997 showed that the percentage of work scheduled at week 7 was typically less than the goal of 60% of the activities worked during the execution week. The Work Management Section was in the process of developing a performance indicator to measure scope growth and control throughout the 12-week process. This would also give an indication of the effect of emergent work on the scope. Comments from the field and on daily schedule report feedback forms indicated a high level of frustration with the accuracy of the schedule. The inspectors assessed that the 12-week work management process was ineffective and had not yet matured. The inability to plan and work maintenance activities according to schedule contributed to the need for additional resources, increased operator burden, and increased equipment out-of-service time.

In some cases, craftsmen contributed to poor work package quality by failing to take advantage of feedback mechanisms. According to the On-Line Scheduling Desktop Guide, work packages should be sent to work groups for pre-job walkdown four weeks prior to the execution week and discrepancies should be resolved with the planner prior to execution. A feedback form was provided in the work package for field comments to the planner following the work to improve package quality. In reality, walkdown quality and feedback varied considerably. Some craftsmen said they had never walked down a package. Some were unsure of what kind of feedback to provide. The I&C Maintenance Section provided a checklist to technicians to fill out when doing walkdowns. The checklist provided some expectations and consistency, but some felt it was too restrictive. Similar comments were made about the post-work feedback form. Some technicians said they had never filled one out. The inspectors reviewed several feedback forms and noted a wide variety of response, from no comment to very detailed comments regarding tools, parts, or reference material required. Maintenance management tracked work package quality by trending the feedback forms; 89% of the work packages from August 1 to December 31 were rated excellent or good. In December and January, 85% were rated excellent or good, and in February 80% were rated excellent or good. These high ratings did not match comments from the field. While some craftsmen noted that work package quality had improved over the last year, most commented that much improvement was needed.

DLC used three work management databases. The automated work order (AWO) system was used for MWRs, FIN work orders, and PMs. The Maintenance Planning and Scheduling System (MPS) was used to maintain information on predictive repetitive tasks, but it did not have true scheduling capability. The Primavera system was used primarily for outage scheduling. The only integration of the three systems was a manually requested download of data from the AWO, which was manually manipulated and fed into Primavera. There was no automated feed of PM data into Primavera. PM tasks were manually entered from information out of MPS. Most planners and schedulers found the current software tools cumbersome and labor intensive. Improvements made in one work package or schedule could not be easily copied onto the next task. Many looked forward to the proposed implementation of the DEMMAND system later this year, but they were unsure of how the DEMMAND system would interface with the existing systems.

The licensee recognized many of the weaknesses in the work management process early in 1997. QSU Maintenance Audit Report BV-C-97-04, dated June 27, 1997, concluded that site maintenance was not fully effective. MPU implemented a Maintenance Improvement Plan (MIP) in June 1997 to improve planning, scheduling, and work control processes. The inspectors reviewed the MIP status report dated February 12. Many action items had been extended more than once or were overdue, such as defining facilities to support the Work Control Center function, developing a schedule that reflects work at the crew level, developing performance indicators relating to milestone adherence and work week implementation, requiring and tracking work package walkdowns, developing job descriptions and filling planning positions, developing planning performance indicators, revising the MEL, and developing a post-maintenance test matrix. Some MIP action items that were successful were development of the FIN Team and establishment of a Work Control Center, though the center was still evolving. The inspectors assessed that the daily screening meeting for new work and the daily work week management meeting were good initiatives developed over the past year. These were generally attended by representatives from the maintenance disciplines, operations, SPED, NPD, health physics, security, FIN, construction, outage management, and planning and scheduling, as appropriate, and promoted consistency and communications in the work management process.

In February, the licensee formed a multi-disciplined Work Management Implementation Team (WMIT) to expand the MIP effort sitewide. The goal of the team was to coordinate site resources and work activities through the work management process to assure nuclear safety, equipment reliability, and economic efficiency. The licensee approved a comprehensive action plan developed by the WMIT on March 13. The initial implementation milestone was targeted for April 6. The inspectors reviewed the action plan and attended the meeting of the Work Performance Review Board that approved the action plan. The plan addressed many of the weaknesses that the licensee identified in the work management process and recommended an aggressive schedule for action items. The WMIT action plan was a good initiative, but it was too early in the process to fully evaluate its effectiveness.

<u>FIN Team</u>

The inspectors reviewed the Fix-It-Now (FIN) program, which was previously reviewed in NRC Inspection Report 50-334 and 412/97-04, Section M1.4. The FIN Team backlog of corrective, general, and minor maintenance was 291 items, of which 204 were minor maintenance activities (as of March 8). FIN backlog had fluctuated between about 250-300 since November. The FIN minor maintenance backlog was reduced from 680 in May 1997 to 280 at the end of the year. A FIN Team priority in 1997 was control room deficiencies. Control room deficiencies were reduced from about 75 in May 1997 to 14 in February. FIN work appeared to be properly categorized in accordance with Maintenance Programs Unit Administrative Procedure (MPUAP) 4.11, "Fix-It-Now Maintenance Program." The FIN Team was conducting a relatively small amount of emergent work (Priority 2 and 3), 4% at Unit 1 and 9% at Unit 2 for the year-to-date. Inspectors noted that the WMIT goal was to have the FIN Team work 80% of emergent work in order to "protect" the schedule, but how this would be accomplished was still under discussion by Maintenance management. Overall, the FIN program was effective in meeting its goals.

Operational Post-Maintenance Testing

The inspectors noted 115 MWRs in the Unit 1 control room and 149 MWRs in the Unit 2 control room that were complete and awaiting operational post-maintenance testing (PMT). The MWRs were sorted in stacks by the physical location of the equipment to be tested (such as turbine building, containment, or auxiliary building).

The inspectors reviewed 38 of the MWRs for the Unit 1 auxiliary building/safeguards area, as well as a sample of MWRs from other Unit 1 and 2 areas. Some deficiencies were noted. Many of the MWRs awaiting operational PMT were from work done during the extended refueling outage on Unit 1 and the current forced outages on both units, but two were for work completed in 1996 (MWRs 051638 and 051256). The work leader signed MWR 044221 as complete on 11/19/97, but the maintenance foreman did not signify review until 3/6/98. The work leader signed MWR 061859 as complete on 4/12/97, but the maintenance foreman did not signify review until 11/15/97. The nuclear shift supervisor signed MWR 060987 as unsatisfactory (PMT failed) on 7/26/97, but the MWR was still in the control room.

Operational PMT requirements were determined and specified on very few of the MWRs. PMT for many of the MWRs was delayed because of current plant conditions; however, there was no tracking method to aid operators in determining when conditions would exist that would allow PMT for a particular MWR. As systems or components were returned to service, operators had to sift through the stacks of MWRs to determine if any of the affected equipment was awaiting PMT and then define the operational PMT to be performed. Operational PMT was not consistently determined during the planning of the MWR. The inspectors reviewed the MWRs awaiting testing and did not identify any safety related or risk significant MWRs which did not have an appropriate PMT specified. The inspectors assessed that planning and control of operational PMT was poor, that it created an unnecessary operational burden on the control room staff, and could result in restoration of equipment to service with inadequate PMT. Station management acknowledged this finding and stated that better controls over PMT identification and tracking would be implemented.

c. Conclusions

The Maintenance organization was adequately staffed to support the plant. Maintenance planning and scheduling processes were not mature, and the licensee has begun implementation of an action plan formed by a multi-disciplined team to improve work management. The inability to plan and work maintenance activities according to schedule contributed to the need for additional resources, increased operator burden, and increased equipment out-of-service time. Tools to improve work package quality, such as pre-job walkdowns and work package feedback forms were not consistently performed. FIN work appeared to be properly categorized and the FIN program was effective in meeting its goals. The poor planning and control of operational PMT created an unnecessary operational burden on the control room staff, as well as the potential to restore equipment to service with inadequate PMT.

M8 Miscellaneous Maintenance Issues

M8.1 (Update) EA 50-334(412)/97-255-01013 Technical Specification (TS) Surveillance Program Deficiencies

a. Inspection Scope (61700)

The Technical Specification Surveillance Review (TSSR) team activities were a key element of licensee corrective actions discussed in Section O8.1. The inspectors conducted the review to provide an independent assessment of the technical adequacy and the level of detail of the licensee's corrective actions that were taken to resolve surveillance program weaknesses and inadequacies identified by the NRC escalated enforcement action in June 1997. The inspectors reviewed several condition reports (CR) that were issued as a result of the review team's activities to evaluate the completeness and quality of the corrective actions planned or implemented to resolve the CR. The inspectors also evaluated the review team's charter, interviewed personnel on the review team and independently reviewed three selected systems that had TS surveillance requirements to verify that the review team had also reviewed each section in detail.

b. Observations and Findings

TS Surveillance Review Team and Their Charter

In general, the team charter required the team to review each Technical Specification's surveillance requirement, verify requirement appropriateness as stated in the most recent TS revision, verify associated surveillance procedures satisfy TS surveillance requirements, verify that the TS/surveillance procedure matrix was correct, and verify scheduling satisfied required time intervals. The charter was approved on December 23, 1997. The review team's organization consisted of a project coordinator and three contractor personnel who had held SRO licenses or were SRO-certified and one SRO licensed at Beaver Valley. The contractor personnel began their review in early November 1997 and the Beaver

Valley SRO began full time review activities in mid-December 1997. These personnel were the central group conducting the major portion of the review. Other personnel were used when needed to supplement certain technical or engineering areas during the review. Identified problems were corrected through the established site condition reporting (CR) system or the normal procedure revision process on an expedited schedule. At the time of this inspection, the review team's activities had resulted in 69 CRs relating to surveillance problems.

Based on interviews with review team members and an evaluation of several problems identified by the review team, the inspectors determined that, for the items reviewed, the team had conducted a detailed review of the TS surveillance requirements. However, the full implementation of the TS surveillance review team was not implemented in a timely manner, such that the licensee's January 30, 1998, commitment date would be met. The late implementation and a larger than anticipated problem resulted in the licensee requesting a commitment date extension from the NRC.

Condition Reports

The following condition reports (CR) were reviewed by the inspectors and were resolved by the licensee, except as noted:

CR No.	Description
• 980258	Westinghouse letter 2DLS-8028 requires that the charging pump starts within 11 seconds of the initiation of an emergency diesel generator (EDG) start. Unit 2 Updated Final Safety Analysis Report (UFSAR) specified times (10 seconds for EDG and 1 second for the charging pump) and TS 4.8.1.1.2.b.7 specified tolerance (plus or minus 10% of 1 second) would allow the 11 second (maximum value) start value for the charging pump specified to be exceeded.
• 980169	TS surveillance requirements 4.7.3.1.b. and c., and 4.7.4.1.b and c. had not been performed for all safety related equipment associated with the Unit 1 river water (RW) and component cooling water systems and Unit 2 service water (SW) and component cooling, primary (CCP) systems. The surveillance requirements involved valve lineup verification and cycling of power operated valves.
• 980321	Determine Unit 2 auxiliary feedwater (AFW) check valve full stroke flow rate requirements. This CR also addressed flow requirements for the Unit 1 high head safety injection (HHSI) check valve flow rate requirements.
• 980305	Two problems reported in CR; 1) existing instrument channel calibration tests did not include a requirement to perform a

functional test following calibration, and 2) when functional test was required it did not meet requirements of IEEE 338 (1977) as discussed in UFSAR, Section 1.8. This CR was in the process of being resolved.

- 980227 Beaver Valley calibrates the reactor coolant system wide range and narrow range resistance temperature detectors (RTD) using the "cross-calibration" method. The TS states that a calibration verifies that the channel responds within the necessary range and accuracy to known values of the parameter that the channel monitors. This CR was in the process of being resolved.

For the CRs that had been resolved by the licensee, the inspectors reviewed the licensee's resolution and corrective actions and found them acceptable as discussed below.

CR 980258 concerned the UFSAR one second start time specified for the charging pump when loaded onto the EDG (step 2 of the load sequencer). The TS allow a plus or minus 10% acceptance time for the one second which means that the charging pump can start up to 1.1 seconds after the 10 second, or less, EDG start time. The Westinghouse analysis and letter 2DLS-8028 assumes a maximum of 1 second. With the 10% allowable acceptance criteria the maximum allowable time could exceed the 11 seconds (10 seconds plus 1.0 second) allowed by analysis. The licensee's immediate corrective action verified that the actual total elapsed time was acceptable in the last surveillance test. The inspectors obtained copies of the last surveillances and verified that times were acceptable. The licensee initiated a UFSAR revision to change the allowed start time to 0.9 seconds which will ensure that the overall start time is less than 11 seconds. A procedure change was initiated and a 10 CFR 50.59 evaluation was also performed.

CR 980321 resulted when new minimum operating point (MOP) curves were calculated by the licensee's engineering department. This is a problem if the MOP is increased and the check valve has not been tested to ensure that it will pass the higher flow rate requirements. Subsequent review by the licensee determined that full flow testing had been satisfactorily performed at, or above, the specified flow rates on the AFW and HHSI check valves with the exception of three AFW valves that were normally tested at a lower flow rate due to normal system operating alignment. Operating Manual Change Notice (OMCN) 2-98-063 was issued to test 2FWE*42B, 43B, and 44B. The OMCN also tested the other AFW system check valves. The inspectors reviewed the completed OMCN and determined that, based on the recorded values, the valves had passed more that the minimum flow required (greater than 233 gpm).

CR 980169 and 980119 concerned verification of flow paths of component cooling water and service water/river water for both units on a monthly basis as required by TS. The inspectors reviewed the licensee's findings and corrective actions. The licensee had identified multiple valves (over 100) that were not verified as required and several power operated valves that were not full-stroke tested every 18 months as required. The licensee also performed an engineering review to establish safety related systems and systems that should have cooling flow verified to ensure that those systems were in the condition/temperature assumed in the accident analysis, although those systems may not be needed for accident mitigation. The licensee performed position verification checks on all additional valves identified by their review. None were found in an incorrect position. The inspectors reviewed several of the licensee's revised surveillance procedures for Unit 2; and, using P&IDs, selected several valves that supply cooling water to safety related components to verify that those valves were included in the listing of valves to be verified. No discrepancies were identified.

The issues identified in the above CRs involve the improper implementation of the applicable Technical Specification surveillance requirements which are examples of violations of NRC requirements. These violations were licensee identified through corrective actions taken to address a previous escalated enforcement action (EA 97-255) documented in NRC Inspection Report Nos. 50-334(412)/97-02and NRC letter to Mr. J. Cross dated July 3, 1997. The root cause for these violations is similar to that for the initial problem. The safety significance of the initial problem remains unchanged. Immediate corrective actions were properly implemented and long-term actions to preclude recurrence are in progress. Therefore, consistent with Section VII.B.4 of the NRC Enforcement Policy, enforcement discretion is exercised and no violation will be issued **(NCV 50-334(412)/98-01-02)**.

Independent Verification of TS Surveillance Review

In addition to the review of the deficiencies identified by the review team, the inspectors independently selected TS surveillance requirements of three systems for review. The surveillance requirements were compared by a line by line review of the TS which were compared with the TS review team's records of their review. The inspectors found that each line of the TS surveillance requirements had been reviewed and that associated surveillance procedures had been compared with the surveillance requirements to ensure compliance. CRs or procedure revisions had been initiated by the review team to correct identified discrepancies.

c. Conclusions

The inspectors determined that the TS review team conducted a thorough and detailed review of the TS surveillance requirements and associated surveillance procedures to ensure that surveillance requirements were satisfied. Licensee actions to identify and resolve problems were comprehensive and technically correct. However, the full implementation of the Technical Specifications surveillance review team was not completed in a timely manner, such that the licensee's January 30, 1998, commitment date could be met. The late implementation and a larger than anticipated problem resulted in the licensee requesting a commitment date extension from the NRC. Independent evaluation of the surveillance review team's activities did not identify any discrepancies in their program.

III. Engineering

E1 Conduct of Engineering

E1.1 Updated Final Safety Analysis Report and System Safety Functional Evaluation Open Item Review

a. Inspection Scope (37551)

The licensee was in the process of reviewing all open items from their Updated Final Safety Analysis Report (UFSAR) review project and from a Safety System Functional Evaluation (SSFE) review of the emergency diesel generator and 4 kV station service system. The inspectors independently reviewed over 30 of the open items. The items were reviewed to ensure the licensee properly reviewed, dispositioned, and prioritized the items.

b. Observations and Findings

The UFSAR and SSFE open items were verified to be generally properly prioritized, reviewed, and dispositioned. More significant items were identified to management through the normal corrective action process. The inspectors also observed that the method for initial identification of UFSAR open items effectively used system engineering knowledge and input.

The inspectors noted two exceptions to the generally effective evaluation of the open items. The inspectors reviewed a UFSAR open item on discrepancies between the UFSAR and other design basis documents for required Unit 1 river water flow. The initial evaluation noted that it was a descriptive issue only and that there was no operational or design non-conformance. The inspectors noted an additional issue with river water flow assumptions. The calculation for the minimum operating point (MOP) curve did not consider all possible lineups of the system. The inspectors determined based on available data that the discrepancy was minor and appeared not to affect the current MOP curve. The licensee wrote a condition report to address the issue and planned to revise the calculation that supported the MOP curve prior to Mode 4. The issue was addressed in Condition Report 980507.

The inspectors reviewed an SSFE open item which noted that the minimum voltage required for safety-related equipment was greater than the TS requirements for degraded voltage relay setpoints which generate an EDG automatic start signal. Inspectors originally questioned the degraded voltage setpoints during a 1991 inspection. In November 1993, engineers evaluated the issue and determined that the minimum voltage setpoints should be administratively controlled at higher values until the TS values could be revised (trip setpoint of >94% and allowable values of >93%). The TS requirements had a trip setpoint of >90% and an allowable value of >88% for the degraded voltage relays.

The inspectors reviewed the administrative controls associated with higher setpoints. The data sheets for the maintenance surveillance procedures were revised to include the higher values. The inspectors determined that the controls were inadequate due to: 1) the reference in the procedure data sheet section identified the TS values (which are non-conservative) and not the determined design basis values; 2) the procedure did not have explicit acceptance criteria that the values would be within the band listed in the tables; 3) the step to notify the shift supervisor that the relay was below allowable values identified the TS value rather than the design basis value. Based on the above, the potential existed that the shift supervisor would not have been notified and would have failed to recognize that the allowable values were not met. The inspectors reviewed completed procedures from 1997 and 1998 and data from 1995 and 1996. The inspectors did not identify any instance where values dropped below the new calculated allowable values.

A TS amendment request to revise the degraded voltage relay setpoints had not been submitted. Several reasons were given for the delays including replacement of relays with more accurate relays (1996) and rework of the design calculations. In 1995, a corrective action tracking item was initiated that required Engineering to request a TS change from Licensing. The original due date was August 1996. The due date was changed four times and had not been completed. The Plant Support Engineering Director informed the inspectors that the item will be completed after gathering additional data on voltage imbalance on the electrical bus to further define the setpoint inaccuracy range. The SSFE open item was considered closed because the issue was being tracked by the licensee's corrective action process. The inspectors noted that the SSFE review was not of sufficient depth for this open item to address the procedure deficiencies and the longstanding TS deficiency.

10 CFR 50 Appendix B Criterion XVI requires that measures shall be established to assure that conditions adverse to quality, such as deficiencies, are promptly identified and corrected. Failure to submit a TS amendment request in a timely manner after a known TS deficiency was recognized and failure to implement adequate procedure revisions to ensure the revised setpoints were met was a violation of 10 CFR 50 Appendix B Criterion XVI. **(VIO 50-334(412)/98-01-03).**

The inspectors noted that two other examples of failures to address known TS deficiencies in a timely manner contributed to LERs in the last year (see Unit 1 LER 97-32 and Unit 2 LER 97-06). After discussions with the inspectors, the licensee planned to perform a review of the engineering backlog to determine if any additional known TS deficiencies existed. This action was appropriate.

c. <u>Conclusions</u>

The licensee recognized a TS deficiency regarding degraded voltage relay setpoints in 1993 and administratively controlled the setpoints through revisions to the maintenance surveillance procedures. The procedure revisions were inadequate and a TS amendment to change the relay setpoints had not been submitted. The failure to address a known TS deficiency in a timely manner and to establish adequate administrative controls to maintain the setpoint was a violation. Two other examples of failures to address known TS deficiencies in a timely manner contributed to LERs in the last year.

E1.2 Emergency Diesel Generator Motor Operated Ground Switch and (Update) EA 50-334(412)/97-255-01013

a. Inspection Scope (37551)

The inspectors reviewed an open item from the TSSRT (previously discussed in Sections O8.1 and M8.1) on the Unit 1 and Unit 2 emergency diesel generator (EDG) motor operated ground switch. The inspectors reviewed the Unit 2 safety and licensing position paper, technical evaluation report (TER) 11704, associated 10 CFR 50.59 evaluations, and relevant design basis documents (IEEE, Regulatory Guides, etc.). In addition, the inspectors attended the Onsite Safety Committee evaluation of the revised TER and 10 CFR 50.59 evaluations.

b. Observations and Findings

The licensee committed to perform a TS surveillance review as part of their response to Notice of Violation EA 97-255. As part of their ongoing review, the licensee identified that the Unit 1 and Unit 2 ground overcurrent protection was not tested as required by TS 4.8.1.1.2.b.4. The TS required that on a loss of power to the emergency busses, all EDG trips with certain exceptions are automatically disabled. The ground overcurrent protection had not been tested since original startup for both units. The cause was inadequate interpretation of TSs which resulted in inadequate procedures. The licensee noted that the other protective signals were appropriately tested. The ground switch was closed only during surveillances.

Failure to comply with TS 4.8.1.1.2.b.4 was a violation of NRC requirements. This violation was identified through corrective actions taken to address a previous escalated enforcement action (EA 97-255) documented in NRC Inspection Report Nos. 50-334(412)/97-02and NRC letter to Mr. J. Cross dated July 3, 1997. The root cause for this violation is similar to that for the initial problem. The safety significance of the initial problem remains unchanged. Immediate corrective actions were properly implemented and long-term actions to preclude recurrence are in progress. Therefore, consistent with Section VII.B.4 of the NRC Enforcement Policy enforcement discretion is exercised and no violation will be issued **(NCV 50-334(412)/98-01-04)**.

The review also identified that the ground switch which provided the isolation feature for the overcurrent protection was a Quality Assurance (QA) category 2 switch. The licensee identified that the switch was QA category 2 in 1992 and at that time recommended that the diesel be declared inoperable during the normal monthly surveillance testing. The switch was only closed during surveillance testing. The licensee did not recognize the failure to perform the surveillance testing of the switch in the 1992 review. Licensing reviews concluded that the Unit 2 EDG needed to be operable during surveillance testing to comply with Regulatory Guide 1.9, Rev. 2, and IEEE-387-1977 (referenced by Regulatory Guide 1.9, Rev. 2). However, Unit 1 was not affected since it did not commit to Regulatory Guide 1.9. The licensing department recommended an upgrade of the EDG ground overcurrent trip bypass equipment to QA category 1 classification to return the design to the originally intended concept and licensing bases. Engineering created a design change that did not change the ground switch to QA category 1. Instead, the modification (Technical Evaluation Report (TER) 11704) isolated the overcurrent protection signal with a QA category 1 component. The TER was installed.

The inspectors reviewed the TER after final approval through the Onsite Safety Committee. The purpose of the TER was to restore the overcurrent trip isolation to a QA category 1 isolation. The inspectors questioned whether all failure modes of the QA category 2 ground switch and ground switch resistor were considered in the design modification since the design modification was apparently "fixing" the lack of a QA category 1 ground switch in the original design. The engineers did not consider the failure modes in their 50.59 analysis prior to TER implementation, because they felt they were outside of the TER evaluation. The inspectors determined that the engineers had forwarded the TER for approval and implementation despite knowing that additional potential failure modes of the ground switch existed, but had not been fully evaluated. The inspectors determined that the 50.59 analysis was too narrowly focused. The engineers subsequently determined that the failure modes identified by the inspectors would not affect the EDG.

Subsequent to TER installation, the engineers identified an additional failure mode that had the potential to significantly damage the EDG during surveillance testing if a fault occurred on the 4 kV line. This new failure mode was a direct result of the design modification. The inspectors recognized that the licensee identified this new subtle failure mode through good engineering investigation. In addition, engineers identified the new failure mode prior to post-installation operability testing.

The engineers also determined that, based on review of Regulatory Guide 1.9, Rev. 2, Regulatory Guide 1.108, Rev.1, IEEE-387-1977, and IEEE-279-1971, the design basis requirements were as follows: 1) surveillance testing does not prevent the EDG from automatically starting in response to a safety signal (does not require operability of the EDG during surveillances; therefore, a category 1 isolation is not required); 2) all protective signals should be in force during surveillance testing; and 3) the bypass circuitry should satisfy the requirement of IEEE-279-1971 at the diesel generator system level. The engineers determined that the original design met the design basis requirements. The engineers also concluded that TER 11704 did not meet the design requirements in that all protective signals would not have been operable during surveillance testing. In addition, the 50.59 evaluation was not accurate in that all failure modes were not evaluated. The engineers created a new TER to restore the original design. The inspectors noted good OSC questioning during the revised TER review. The reversal of the design change was completed prior to surveillance testing on the EDG; therefore, no adverse safety consequences resulted. The engineering group incorporated lessons learned from this event in their training.

10 CFR 50, Appendix B, Criterion III (Design Control), requires, in part that design changes shall be subject to design control measures commensurate with those applied to the original design. In this case the design control measures for a modification to the Unit 2 emergency diesel generator (EDG) ground overcurrent trip isolation feature were inadequate. Specifically, the failure mode analysis for this design change did not evaluate failures of the quality assurance category 2 ground switch and resistor. The failure mode analysis also did not identify or evaluate an additional failure mode which had the potential to damage the EDG during surveillance testing if a fault occurred on the 4 kV line. This was a violation of 10 CFR 50, Appendix B, Criterion III **(VIO 50-334(412)/98-01-05)**. The failure to understand the design and licensing bases prior to performing the modification was a weakness.

c. Conclusions

The Technical Specification surveillance review team identified that the Unit 2 emergency diesel generator ground switch was not tested as required by Technical Specifications. This was attributed to inadequate implementation of TS requirements into surveillance procedures.

Engineers failed to fully evaluate all potential failure modes prior to installation of a modification to the Unit 2 emergency diesel generator ground overcurrent trip isolation feature which was an example of inadequate design control and a violation. Specifically, the failure mode analysis for this design change was too narrowly focused in that failures of the quality assurance category 2 ground switch and resistor were not fully evaluated. The failure mode analysis also did not identify or evaluate an additional failure mode which had the potential to damage the EDG during surveillance testing if a fault occurred on the 4 kV line.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) URI 50-334(412)/97-01-03: UFSAR Verification Project Follow-up

This URI is closed per regional inspection guidance and an inspection follow-up item is opened to track the UFSAR Verification Project Follow-up **(IFI 50-334(412)/98-01-06)**.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

a. Inspection Scope (83750)

The inspectors reviewed the licensee's programs for internal and external dosimetry, including personnel dosimetry records, calibration and utilization of whole body counters, and respirator issue and maintenance. Additionally, the inspectors reviewed current radiological work at both units and the most recent audit conducted as part of the National Voluntary Laboratory Accreditation Program (NVLAP). The inspection was accomplished by a review of plant documents and procedures, interviews with personnel and walkdowns of the related areas.

b. Observations and Findings

The licensee's principle means of determining qualitative and quantitative information on internal exposure is via the use of whole body counting. The licensee maintains two whole body counters, one using NaI(Tl) detectors and the other intrinsic germanium. The NaI(Tl) system is used regularly to perform routine bioassays, and as a screening tool for potential internal exposures. The system has been calibrated and is maintained in such a manner as to meet the necessary sensitivities for the various radionuclides present in the plant. Documentation of the annual calibration and a semi-annual calibration verification are maintained and distributed to pertinent staff members and was reviewed by the inspector. At the time of this specialist inspection, the licensee had just completed its calibration of one of the counters and was preparing to start calibration of the second counter. Source and background checks were performed every four hours during operation by the licensee as a quality control measure. Documentation of these results was readily available at the whole body count trailer where these two devices were located. Currently, the computer that interfaces with the counters does not have the capability to communicate directly with the licensee's health physics database, so data transfer is by hand. During the spring and fall, availability of the counters, especially the NaI(Tl)-based system, is significantly diminished due to temperature changes in the trailer which cannot be appropriately compensated for with the limited HVAC system for this facility. However, no incidences of inaccurate surveys of personnel were found by the inspectors.

The licensee's external dosimetry program utilizes thermoluminescent dosimeters (TLDs) for dose of record, and electronic dosimeters for more real-time exposure data. The licensee's program for external dosimetry was most recently reviewed by NVLAP (Audit # 100521) on October 29-31, 1997. Three deficiencies were indicated in the audit report which required a licensee response. The licensee has responded, as required, and has received its recertification. The licensee's health physics database incorporates results from the TLDs and the electronic dosimeters to allow for tracing of worker exposures in near real-time. Additionally, this database is utilized for RWP and ALARA review issuance and data tracking.

The licensee utilizes and maintains a variety of respiratory protection devices, especially a large number of self-contained systems, due to the presence of sub-atmospheric containment environments while at power. Annual training and fit test programs are appropriately implemented and maintained. Data tracking and issuance are currently performed using a specialized database, which is incompatible with the main health physics database. This weakness is currently being addressed by the licensee. During outage operations, a contractor is utilized to perform respirator cleaning, with 100% review of returned respirators conducted by the licensee. The majority of respirators currently utilized by the licensee are for industrial hygiene purposes, and are not needed for minimizing internal radionuclide exposures.

The inspectors reviewed the licensee's established occupational exposure goals for 1998. The site goal of 186 person-rem is based on a full year operating goal at Unit 1 of 28 person-rem, a partial operating year goal at Unit 2 of 8 person-rem, and a refueling outage (2R07) goal of 150 person-rem. Through the first seven weeks of 1998, the licensee was ahead of its year-to-date projections due to the unplanned shutdown of both units. At Unit 2, over 600 millirem had been expended working on valve repair/modifications in the pressurizer cubicle. At Unit 1, a system modification would also entail work in their pressurizer cubicle. The licensee's annual goal does not include a contingency dose for unplanned outages.

The inspectors conducted tours of various portions of the radiologically controlled areas (RCAs) at both units. At Unit 2, the inspectors toured accessible areas of the containment, auxiliary, waste, condensate, safeguards and turbine buildings. Of particular note was the significant increase in the use of survey maps posted out in the RCA. Each map was clearly dated, and based on inspectors' verification, accurately indicated radiological conditions at the facility. The inspectors also noted the detailed briefings being provided to workers entering the Unit 2 pressurizer cubicle, and the use of an ALARA low dose waiting area for work there. At Unit 1, the inspectors toured accessible RCA locations in the auxiliary, waste, fuel, safeguards and turbine buildings. As at Unit 2, local survey maps were now available to workers, in addition to those located at the main RCA entrance.

c. Conclusions

The licensee has established effective programs for external dosimetry, internal dosimetry through the use of whole body counting, and respiratory protection program. Improvements in radiological postings were also observed.

R8 Miscellaneous RP&C Issues (92904)

R8.1 (Closed) Unresolved Item 50-334(412)/97-05-10: Spraying Air Particulate Filters with a Commercial Brand Clear Acrylic.

This item was opened pending the licensee's review of the effect of the sample preparation method of spraying the air particulate filters with a commercial brand clear acrylic. During an in-office inspection on March 17, 1998, the inspectors reviewed the results of the licensee's study to determine if spraying acrylic on the filters would have an effect on the analytical results. The licensee compared the analytical results of the air particulate filters with and without the acrylic coating. The results were in agreement and the effect of the sample preparation method on the analytical results was negligible. Nonetheless, the licensee discontinued the use of the acrylic spray and revised the procedure, as appropriate. The inspector concluded that no violation of NRC requirements occurred and this item is closed.

R8.2 (Closed) Violation 50-334/97-08-04: Radiological workers failing to follow procedures. All licensee short and long-term corrective actions, except for reviews of their effectiveness during the upcoming Unit 2 refueling outage, have been completed. Changes were made to the licensee's Health Physics Manual and related implementing procedures. Survey maps of the RCA are now located throughout the plant. No additional examples of workers in the radiologically controlled areas (RCAs) without knowledge of their area exposure rates have been identified. This item is closed.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on March 31, 1998. The licensee acknowledged the findings presented.

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

PARTIAL LIST OF PERSONS CONTACTED

DLC

J. Cross, President, Generation Group
R. Brandt, Vice President, Nuclear Operations/Plant Manager
R. LeGrand, Vice President, Operations Support
S. Jain, Vice President, Nuclear Services
M. Pergar, Acting Manager, Quality Services Unit
B. Tuite, General Manager, Nuclear Operations
R. Hansen, General Manager, Maintenance Programs Unit
R. Vento, Manager, Health Physics
D. Orndorf, Manager, Chemistry
F. Curl, Manager, Nuclear Construction
J. Matsko, Manager, Outage Management Department
T. Lutkehaus, Manager, Maintenance Planning & Administration
T. Cosgrove, Coordinator, Onsite Safety Committee
J. MacDonald, Manager, System & Performance Engineering
K. Beatty, General Manager, Nuclear Support Unit
J. Arias, Director, Safety & Licensing
W. Kline, Manager, Nuclear Engineering Department
R. Brosi, Manager, Management Services
O. Arredondo, Manager, Nuclear Procurement

NRC

D. Kern, SRI
G. Dentel, RI
F. Lyon, RI

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61700:	Surveillance Procedures and Records
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 83750:	Occupational Exposure
IP 92901:	Follow-up - Operations
IP 92902:	Follow-up - Maintenance
IP 92903:	Follow-up - Engineering
IP 92904:	Follow-up - Plant Support

ITEMS OPENED, CLOSED AND DISCUSSED

Opened

50-334(412)/98-01-03	VIO	Failure to Submit TS Amendment in a Timely Manner and Implement Adequate Administrative Controls After a Known TS Deficiency was Recognized (Section E1.1)
50-412/98-01-05	VIO	Failure to Evaluate All Failure Modes Associated with a Design Change for EDG Ground Overcurrent Trip Isolation (Section E1.2)
50-334(412)/98-01-06	IFI	UFSAR Verification Project Follow-up (Section E8.1)

Opened/Closed

50-412/98-01-01	NCV	Inadequate Procedure Resulted in Feedwater Isolation (Section O4.1)
50-334(412)98-01-02	NCV	Various examples of improper implementation of TS surveillance requirements (Section M8.1)
50-334(412)/98-01-04	NCV	Inadequate Interpretation of TS Resulted in Inadequate Procedures - Ground Overcurrent Protection Not Tested as Required by TS (Section E1.2)

Closed

50-334(412)/97-01-03	URI	UFSAR Verification Project Follow-up (Section E8.1)
50-334(412)/97-05-10	URI	Spraying Air Particulate Filters with a Commercial Brand Clear Acrylic (Section R8.1)
50-334/97-08-04	VIO	Radiological Workers Failing to Follow Procedures (Section R8.2)

Updated

50-334(412)/97-255-01013	EA	TS Surveillance Program Deficiencies - EDG Load Test (Sections O8.1, M8.1, and E1.2)

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
AWO	Automated Work Order
BVPS	Beaver Valley Power Station
CCP	Component Cooling, Primary
CR	Condition Report
DLC	Duquesne Light Company
EA	Enforcement Action
EDG	Emergency Diesel Generator
FIN	Fix-It-Now
FME	Foreign Material Exclusion
FWIV	Feedwater Isolation Valve
GL	Generic Letter
HHSI	High Head Safety Injection
I&C	Instrument & Controls
IEEE	Institute of Electrical and Electronics Engineers
IST	In-service Test
LER	Licensee Event Report
MEL	Material Equipment List
MIP	Maintenance Improvement Plan
MOP	Minimum Operating Point
MPS	Maintenance Planning & Scheduling
MPU	Maintenance Program Unit
MPUAP	Maintenance Programs Unit Administrative Procedure
MWR	Maintenance Work Request
NCV	Noncited Violation
NOV	Notice of Violation
NPD	Nuclear Procurement Department
NPDAP	Nuclear Power Division Administrative Program
NVLAP	National Voluntary Laboratory Accreditation Program
OMCN	Operating Manual Change Notice
PDR	Public Document Room
PM	Preventive Maintenance
PMT	Post-Maintenance Testing
PORV	Power Operated Relief Valve
QSU	Quality Services Unit
RCA	Radiologically Controlled Area
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RP&C	Radiological Protection & Chemistry
RP&C	Radiological Protection & Chemistry
RTD	Resistance Temperature Detector
RW	River Water
SSFE	System Safety Functional Evaluation
SW	Service Water
TER	Technical Evaluation Report
TLD	Thermoluminescent Dosimeter

TS	Technical Specification
TSSR	Technical Specification Surveillance Requirement
TSSTCO	Technical Specification Surveillance Compliance Oversight
UFSAR	Updated Final Safety Analysis Report
USQ	Unreviewed Safety Questions
VIO	Violation
WMIT	Work Management Implementation Team