U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.	93-16 93-17
Docket Nos.	50-334 50-412
License Nos.	DPR-66 NPF-73
Licensee:	Duquesne Light Company One Oxford Center 301 Grant Street Pittsburgh, PA 15279
Facility:	Beaver Valley Power Station, Units 1 and 2
Location:	Shippingport, Pennsylvania
Inspection Period:	July 21 to August 23, 1993
Inspectors:	Lawrence W. Rossbach, Senior Resident Inspector Peter P. Sena, Resident Inspector Scot A. Greenlee, Resident Inspector

Approved by: W J Lazarus 9/8/93
W. J. Lazarus, Chief, Reactor Projects Section 3B   Date

Inspection Summary

This inspection report documents the safety inspections conducted during day and backshift hours of station activities in the areas of: plant operations; maintenance and surveillance; engineering; plant support; and safety assessment/quality verification.

EXECUTIVE SUMMARY
Beaver Valley Power Station
Report Nos. 50-334/93-16 & 50-412/93-17

Plant Operations

Plant operator performance was a strength. Operators responded to four unexpected plant transients. Three of the transients were caused by equipment malfunction; the fourth was caused by instrumentation and control technicians during maintenance. In all cases, operators acted appropriately to minimize the effects of the transient, and no power reductions resulted.

Operator overtime is frequently required in non-outage periods because of staffing levels. Overtime scheduling frequently requires the operators to work "short swings" (8 hours on, 8 hours off, and then 8 hours on). Increased management focus is being directed to minimize overtime scheduling problems. Increased operator staffing levels have been approved, and should be effective in 1995.

The licensee incorrectly interpreted a technical specification involving an inoperable nuclear instrument. Use of the interpretation has been discontinued, and a license amendment is being pursued.

Maintenance

Maintenance engineers demonstrated mixed performance in support of plant maintenance. Engineering support to resolve airlock door deficiencies, identification of diesel generator governor motor operated potentiometer deficiencies, and development of upgraded procedures was found to be good. However, maintenance preplanning could have been improved to ensure that a post-maintenance adjustment to the diesel governor motor operated potentiometer was completed following its replacement. Additionally, limited corrective action by inservice testing engineers to a previously identified deficiency resulted in the use of incorrect baseline vibration data for an auxiliary feedwater pump. System engineers unfamiliarity with the hydrogen analyzers, as well as an inadequate procedure, resulted in an inoperable analyzer. This was a non-cited violation.

Additional procedural deficiencies were noted with a corrective maintenance procedure which resulted in pressurizer spray control valves going shut. A calibration procedure also needed improvement with respect to identifying a disabled control annunciator. These procedures had not yet been processed through the licensee's procedure upgrade program. An impressive improvement in procedure quality was, however, noted with a solid state protection system procedure which had been upgraded.

(EXECUTIVE SUMMARY CONTINUED)

The licensing department provided acceptable assistance to airlock maintenance by pursuit of NRC enforcement discretion. However, a technical specification interpretation for airlock testing used an incorrect basis as it relied on proposed regulations which had not been incorporated into the current 10 CFR 50, Appendix J.

Engineering

Engineering support of plant operations was good. The inspectors noted technically accurate evaluations of core axial flux offset at Unit 1, and an equivalent replacement for a failed Class 1E relay at Unit 2.

The licensee did not have a periodic testing program in place to verify that the Unit 2 supplemental leak collection and release system will perform satisfactorily in service. The licensee does, however, intend to develop such a test. This issue is identified as an **unresolved item (50-412/93-01)** pending NRC review of the new procedure. A minor deficiency was noted in the documentation to support the current configuration of the plant safety monitoring system. The licensee promptly upgraded the documentation.

Plant Support

Plant support activities were good as evidenced by the chemistry staff's proper use of diesel technical manual instructions and the emergency preparedness staff evaluation of station emergency assessment capability. Also, the quality assurance organization is maintaining an employee concern program which has the basic characteristics of a sound program. Continued deficiencies have been noted in the control of transient material. The licensee also incorrectly interpreted a regulation concerning the posting of notices to workers. The manner of posting NRC Form 3 was a violation of NRC requirements; however, due to the low safety significance and commitments by the licensee to correct the deficiency, the violation is not being cited.

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DETAILS

1.0 MAJOR FACILITY ACTIVITIES

Unit 1 operated at full power throughout this inspection period except for a power reduction to approximately 60 percent power from August 6 to 9 due to lower system demand and a reduction to 98 percent on July 28 due to the influence of hot weather on plant efficiency.

Unit 2 operated at full power throughout this inspection period except for several power reductions to between 89 percent and 92 percent power due to the influence of hot weather on plant efficiency.

2.0 PLANT OPERATIONS (71707)

2.1 Operational Safety Verification

Using applicable drawings and check-off lists, the inspectors independently verified safety system operability by performing control panel and field walkdowns of the following systems: diesel fuel oil; diesel air intake, exhaust and vacuum; auxiliary feedwater; and radiation monitoring system. These systems were properly aligned. The inspectors observed plant operation and verified that the plant was operated safely and in accordance with licensee procedures and regulatory requirements. Regular tours were conducted of the following plant areas:

- Control Room
- Auxiliary Buildings
- Switchgear Areas
- Access Control Points
- Protected Areas
- Spent Fuel Buildings
- Diesel Generator Buildings
- Safeguards Areas
- Service Buildings
- Turbine Buildings
- Intake Structure
- Yard Areas
- Containment Penetration Areas
- Waste Handling Building

During the course of the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration, and plant conditions. The inspectors verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. The inspectors found that control room access was properly controlled and a professional atmosphere was maintained. Inspectors' comments or questions resulting from these reviews were resolved by licensee personnel.

Control room instruments and plant computer indications were observed for correlation between channels and for conformance with technical specification (TS) requirements. Operability of engineered safety features, other safety related systems, and onsite and offsite power sources were verified. The inspectors observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Compliance with TS and implementation of appropriate action statements for equipment out of service was inspected. Logs and records were reviewed to determine if entries were accurate and identified equipment status or deficiencies. These records included operating logs, turnover sheets, system safety tags, and the jumper and lifted lead book. The inspectors also examined the condition of various fire protection, meteorological, and seismic monitoring systems.

2.2 Use of Overtime for Nuclear Control Operators

The inspectors reviewed the use of overtime for nuclear control operators. Overtime records for the period of April 5 to July 25, 1993, were reviewed, and the results were compared to the overtime requirements contained in the technical specifications (TS). No TS violations were found; however, the inspectors had the following observations:

- Frequently, operators are required to work what they describe as a "short swing." This involves working an 8-hour shift, then having 8 hours off, followed by another 8-hour shift. If watch reliefs are conducted on time, this rotation can lead to a TS violation. TS require at least 8 hours between work periods, <u>including</u> shift turnover time. All of the operators interviewed indicated that they try to relieve the watch on time, even when working a "short swing."

- Staffing levels are such that frequent overtime is required even in non-outage periods. TS state that the objective shall be to have operating personnel work a normal 8-hour day, 40-hour week while the plant is operating.

The inspectors' observations were discussed with the Unit 1 and Unit 2 Operations Managers. The Operations Managers were aware of the problems with staffing levels and the use of overtime. They stated that an increase in operator staffing had been approved, but the approved levels would not be achieved until 1995. Additionally, the inspectors were informed that Duquesne Light Company plans to increase management attention on the scheduling of operator overtime. Better management of overtime scheduling should help minimize the use of "short swings," and ensure compliance with TS.

2.3 Unit 1 Feedwater Transient

On July 29, 1993, at 1:55 p.m., the flow indicator (FI-FW-476) for feedwater to the 'A' steam generator began to act erratically and finally failed high. Due to a perceived flow error in the steam generator water level control system, main feedwater regulating valve FCV-FW-478 began to automatically close and the 'A' steam generator level deviation annunciator alarmed to alert operators to the feedwater control problems. Operators properly diagnosed the cause of the transient and placed the feedwater regulating valve in manual to regain steam generator level control. The operator's proper action minimized the steam generator level decrease from 44 percent to 38 percent. Feedwater control was placed back in automatic after selecting feedwater channel FW-477 as the controlling channel. The failed instrument was returned to service following replacement and testing of the multiplier/divider module. Overall, operators took proper action in response to the instrument failure and thus minimized its effect on the plant.

2.4 Nuclear Instrumentation Technical Specification Interpretation

Unresolved item number 50-412/92-15-01 involved the licensee's use of a technical specification (TS) interpretation for power range nuclear instrument N-44 at Unit 2. An identical failure of nuclear instrument N-43 occurred at Unit 1 (see NRC Inspection Reports 50-334/93-13 and 50-412/93-14); however, the same technical specification interpretation was not needed since the nuclear instrument was returned to service within the allowed outage time. Nuclear instrument N-43 was declared inoperable on June 25, 1993, at 9:14 p.m., due to blown control power fuses. This fuse failure affected the control portion of N-43 power range channel which provides input into solid state protection. Accordingly, the channel was placed in a tripped condition per TS 3.3.1.1. However, the upper and lower excore detector portion of the power range channel, including detector output (*i.e.*, power indication) was not affected by the blown fuses. Thus power tilt monitoring for this quadrant of the reactor core was not degraded. TS 3.3.1.1 (action 2b) requires that the inoperable power range channel be placed in a tripped condition and either reduce power to ≤75 percent within 4 hours or determine the quadrant power tilt ratio (QPTR) every 12 hours using the movable incore detectors (per TS 4.2.4.c). The licensee's position was that if the excore detector output could be accurately and adequately judged as reliable, then the use of the excore detectors for QPTR determination is equivalent to the use of incore detectors for this action statement. The licensee considered this interpretation to be consistent with NUREG 1431, Volume 2, "Standard Technical Specifications, Westinghouse Plants," since tilt monitoring for this portion of the reactor core was not actually degraded. The excore detectors are normally used for QPTR determination per TS 3/4.2.4. Although the licensee's technical specification basis is satisfactory, the TS explicitly required the use of the incore system. The licensee has subsequently suspended the use of this TS interpretation. The inspectors had no further comments. This **unresolved item (50-412/92-15-01)** is **closed**.

2.5 Unit 2 Feedwater Transient

At 5:00 p.m. on August 12, 1993, the 'B' main feedwater regulating valve closed by approximately 50 percent. The regulating valve was in manual control because steam generator water level calibration checks were in progress on the 'B' steam generator. No valve position adjustments were performed while in manual control. The reactor operator immediately recognized the problem and attempted to open the valve using manual control. Initially, there was no response from the valve. The valve then responded slowly, and the operator was able to regain control over steam generator water level. Duquesne Light Company monitored the controller output and performed other trouble shooting, but was not able to determine the cause of the event. There have not been any problems with the valve since. Additional trouble shooting is planned for the upcoming refueling outage.

An NRC resident inspector was in the control room at the time of the event. The inspector observed that the operators were quick to recognize the problem and responded appropriately. A delay in responding to this event could easily have led to a reactor trip.

2.6 Loss of Emergency Response Facility (ERF) Substation

At 2:45 a.m. on August 18, 1993, the Beaver Valley Power Station lost all 4 kV and 480 Vac power associated with the ERF substation. The ERF substation supplies power to the ERF and to non-safety-related load centers at Unit 1 and Unit 2. The loss of power to the ERF required Duquesne Light Company to evaluate their ability to implement their emergency plan. Loss of power to the ERF is discussed in more detail in Section 5.3 of this report. The loss of power to the Unit 1 and Unit 2 load centers was significant only at Unit 2. Specifically, Unit 2 lost four out of five air compressors. The air systems at Unit 2 are not safety-related; however, many of the air system loads are required for continued plant operation (*i.e.*, the main steam isolation valves and the feedwater regulating valves).

Plant operators at Unit 2 were able to realign the air systems, using the remaining air compressor, eliminating the need for a plant shutdown. The inspectors concluded that this was a significant accomplishment, and indicated a detailed level of knowledge and training on the plant air systems. This conclusion was based partly on the level of procedural support available to the operators. There was not an integrated procedure which addressed this particular situation. The abnormal operating procedures which previously addressed loss of instrument air and loss of containment instrument air were deleted. Subsequently, operator response to a loss of these air systems was covered by alarm response procedures. None of the air system alarm response procedures assume a loss of power to multiple compressors as a probable cause for the alarm; thus, the procedures do not provide specific actions for a loss of the ERF substation.

The loss of power at the ERF substation also caused a loss of power to the Unit 2 steam generator blowdown radiation monitor. Loss of power to this monitor causes the steam generator blowdown containment isolation valves to shut. Consequently, Duquesne Light Company made a 4-hour 10 CFR § 50.72 report because of an automatic engineered safety feature actuation. The actuation had no safety significance or consequence.

The loss of power at the ERF substation was caused by a programmable controller (PC). The PC (a Gould Modicon 484) initiated trip signals to the 4 kV feeder breakers in the substation. The reason why the PC initiated the signals is not known. The PC normally functions to start the ERF substation diesel generator, and sequence loads onto the generator when a loss of offsite supply to the substation occurs. The faulty PC was sent back to the vendor for analysis of the failure mechanism. Duquesne Light Company has had past, similar problems with PCs in the ERF substation. On four occasions since 1988, a PC has tripped open one of the two 4 kV ERF substation feeder breakers. Three times the cause was attributed to a faulty power cable. A cause was not determined for the fourth event. The power cable for the PC which caused the August 18 event was checked and found satisfactory.

Duquesne Light Company is investigating the following additional items which came to their attention following the loss of ERF substation power:

(1) The ERF substation diesel generator did not start on a loss of 4 kV power. This surprised the plant operators, but the system response was according to design. The diesel will not start if 138 kV power is still available to the ERF substation transformers. Duquesne Light Company is planning to evaluate this design.

(2) Another PC (a Gould Modicon 584), responsible for ERF substation diesel generator load shedding, was found in a failed condition. The cause of the failure is currently not known.

(3) One of the 484 PC outputs had been disabled. The output was for control of a 4 kV breaker which supplies a Unit 2 load center. The disabled output was not tagged to indicate the reason for the modification.

(4) A difference was noted between the 484 PC software and the software documentation. Duquesne Light Company considers that the actual software is correct (*i.e.*, the documentation is wrong); however, they plans to verify this contention and determine the reason for the difference.

Duquesne Light Company is keeping the resident inspectors informed of their progress in resolving the issues noted above.

3.0 MAINTENANCE (62703, 61726, 71707)

3.1 Maintenance Observations

The inspectors reviewed selected maintenance activities to assure that: the activity did not violate Technical Specification Limiting Conditions for Operation and that redundant components were operable; required approvals and releases had been obtained prior to commencing work; procedures used for the task were adequate and work was within the skills of the trade; activities were accomplished by qualified personnel; radiological and fire prevention controls were adequate and implemented; QC hold points were established where required and observed; and equipment was properly tested and returned to service.

The maintenance work requests (MWRs), preventive maintenance procedures (PMPs), and relay calibration procedures (RCPs) listed below were reviewed. The observed activities were properly conducted without any notable deficiencies unless otherwise indicated.

1/2 PMP-75-480V Motor - 1E	480 Vac Motors Inspection and Lubrication (for 2QSS*P24B)
1/2 RCP-11-PC	Calibration of Ground Fault Relay 50VF202G
1/2 RCP-38	Calibration of Overcurrent Relay 51VF202
1/2 RCP-31-PC	Calibration of Auxiliary Relay 50VF202X
MWR 21868	Replace Failed Silicon Controlled Rectifier for Overcurrent Relay 51VF202
MWR 21853, 21567	MOV-RW-102B1 and 1902B2 Motor Replacement
MWR 22133	Personnel Airlock "O-Ring" Replacement (see Section 3.1.1)
MWR 19133	Emergency Diesel Generator 2EGS-EG2-2 Motor Operated Potentiometer Replacement

On February 18, 1993, the No. 2 Emergency Diesel Generator (EDG) for Unit 2 experienced slight load fluctuations while being unloaded following its monthly surveillance test. Duquesne Light Company determined that the problem did not effect diesel operability. Duquesne Light Company attempted to determine the cause of the problem during some of the subsequent monthly surveillance tests. NRC Inspection Report Numbers 50-412/93-09 and 50-412/93-13 discuss some of these efforts.

During the July surveillance test on the No. 2 EDG, detailed monitoring of various parameters identified a "bad spot" on the motor operated potentiometer in the governor control circuit. A maintenance work request was generated to replace the motor operated potentiometer prior to the August surveillance test.

The inspectors observed the replacement of the motor operated potentiometer and the post-maintenance testing for the No. 2 EDG. Additionally, all paperwork associated with the replacement was reviewed, including the procurement documents. During the post-maintenance test (the monthly surveillance test), the inspectors questioned why the no-load frequency of the EDG was 62 Hz. The inspectors were told by the shift supervisor that once the frequency was adjusted from the control room, the no-load frequency would return to the adjusted frequency (60 Hz) during the next start. Based on this conclusion, the diesel was loaded and the surveillance test was completed. Monitoring of various parameters during the test showed no problems with load fluctuation.

Prior to declaring the EDG operable, a Duquesne Light Company engineer found a passage in the EDG technical manual which indicated that an adjustment to the motor operated potentiometer would be required to set the no-load frequency of the unit back in the 60 Hz range. The motor operated potentiometer is automatically reset to a preset resistance (which is adjustable) when the EDG is shutdown. The EDG was then restarted (no-load frequency was 62 Hz), and the motor operated potentiometer was adjusted. Following this, the complete monthly surveillance test was repeated (the no-load frequency was about 60.7 Hz), and then the EDG was declared operable.

The inspectors' review of the maintenance, including a review of the EDG technical manual, concluded the following:

(1) The final troubleshooting effort which identified the deficient motor operated potentiometer was very well thought-out and implemented.

(2) The maintenance procedure used to replace the motor operated potentiometer should have been more thoroughly researched. Enough information was available in the EDG technical manual for the maintenance planner to identify the potential need to adjust no-load frequency.

The inspectors' observation concerning maintenance planning was discussed with the electrical maintenance engineer.

MWR 17318, Troubleshooting of Loop 'C' Tave Deviation Alarm

The Unit 1 loop 'C' average reactor coolant system temperature (Tave) deviation alarm had been in an alarm condition even though no mismatch existed with reference average temperature (Tref). Proper job preplanning traced the problem to the Tave deviation comparator. Good job-site support by the I & C first line supervisor was evident and allowed for the proper diagnosis and repair of the comparator. One minor problem did occur which involved an unexpected pressurizer level deviation alarm. No actual level deviation occurred as pressurizer level control was already in manual. The maintenance procedure (1CAL-6-T408E) did not specify that this annunciator would be disabled when the Tave input to pressurizer level control was removed. The inspectors were informed that the procedure would be updated via the procedure critique process.

3.1.1 Unit 1 Personnel Airlock Repairs and Enforcement Discretion

On August 5, 1993, the inspectors observed system engineering personnel conduct an airlock seal leak test following the completion of maintenance activities inside containment. Technical Specification 4.6.1.3 requires the O-ring gap of each airlock door to be pressured to ≥40.0 psig for at least 2 minutes with no detectable seal leakage. During the conduct of OST 1.47.1, "Containment Airlock Door Type B Leak Test," unacceptable leakage was detected on the inner door while the outer door tested satisfactorily. The licensee declared the inner door inoperable and applied Technical Specification 3.6.1.3 which requires that the door be returned to operable status within 24 hours. Earlier this same day, the acting Maintenance Manager demonstrated good foresight by ensuring the necessary replacement parts were available and that the MWR was already generated just in case the airlock seal test failed. MWR 22133 was subsequently activated for the replacement of the inner door O-rings and inspection of sealing surfaces.

Following the O-ring replacement, the inspectors observed the post-maintenance testing of the seals in which the O-ring gap was pressurized to 40.0 psig. This test was initially conducted with zero differential pressure across the inner door (both containment pressure and airlock pressure were 9.5 psia). The door seals satisfactorily passed this local leak test. The inspectors considered this to be an acceptable post-maintenance test. (see Section 3.1.2 for further discussion). After the maintenance crew exited the airlock, OST 1.47.1 was performed with the airlock at atmospheric pressure. Under new test conditions, with a 5.2 psid differential pressure across the inner door (acting to force open the door), a slight seal leak was detected. Under design basis accident conditions, positive containment pressure would act to seal the door shut. Although the initial post-maintenance test did provide acceptable indication of door sealing capability, the failed results of OST 1.47.1 could not be discounted as this was the last valid test performed. Per technical specifications, the inner door appropriately remained inoperable, and the outer door was padlocked closed. However, with the outer door locked, further attempts to repair the inner door are not possible. Accordingly, the licensee requested the NRC to exercise enforcement discretion to allow the outer door to be unlocked for repairs to the inner door. This was also necessary to allow the licensee access to containment for any other necessary equipment repairs. After reviewing the licensee's technical justification, including compensatory measures, the NRC granted enforcement discretion. The NRC concluded that the licensee's action involved minimal or no safety impact and that the exercise of enforcement discretion is warranted from a public health and safety perspective. Subsequent breech ring adjustment resulted in the satisfactory repair of the inner door. On August 11, the airlock door passed the seal leak test and the door was declared operable. Overall, the licensee's request for enforcement discretion was appropriate. The support provided by maintenance personnel and the system engineer to resolve the door deficiencies was good.

3.1.2 Containment Airlock Door Testing Requirements

The inspector reviewed the licensee's technical specification interpretation on airlock testing to ensure proper post-maintenance testing of the airlock was completed following O-ring seal replacement. Technical Specification (TS) 4.6.1.3.b.2 requires an overall airlock leak test, at not less than Pa (peak internal containment pressure during design basis accident - 40.0 psig), "upon completion of maintenance which has been performed on the airlock that could affect the airlock sealing capability." The licensee's position was that O-ring replacement and breech ring travel adjustment does not require the performance of the overall airlock leakage test. The licensee based this position on an October 29, 1986 proposed rule to 10 CFR 50, Appendix J. This proposed rule stated, in part, that "whenever maintenance, other than on door seals has been performed on an airlock, a complete airlock test at test pressure not less that Pa is required." However, this was only a proposed rule and was never incorporated into the current regulations. In the NRC basis for TS 4.6.1.3.b.2 an overall airlock test following maintenance is only applicable while in Mode 5 (cold shutdown) or Mode 6 (refueling) prior to plant startup. Since the O-rings were replaced while in Mode 1 (power operation), the overall airlock leakage test was not required. Therefore, the local leak rate test of the O-rings at 40.0 psig was a proper post-maintenance test. However, the licensee's interpretation is incorrect, as an O-ring replacement does constitute maintenance which affects the airlock sealing capability and would require an overall airlock test (per the licensee's own technical specification) if the plant was in Modes 5 or 6. The inspectors were concerned in this case with the licensee's reliance on proposed regulations vice use of the currently existing regulations. In order to clarify this technical specification, the licensee has initiated a technical specification change.

3.2 Surveillance Observations

The inspectors witnessed/reviewed selected surveillance tests to determine whether properly approved procedures were in use, details were adequate, test instrumentation was properly calibrated and used, technical specifications were satisfied, testing was performed by qualified personnel, and test results satisfied acceptance criteria or were properly dispositioned. The operational surveillance tests (OSTs), and maintenance surveillance procedures (MSPs) listed below were reviewed. The observed surveillance activities were properly conducted without any notable deficiencies unless otherwise indicated.

OST 1/2.44A.1 — Unit 1/2 Control Room Emergency Habitability System Check

OST 1.47.1 — Containment Airlock Door Type 'B' Leak Test (see Section 3.1.1)

1MSP 1.04-I — Sold State Protection System (SSPS) Train 'A' Bi-Monthly Test

The channel functional test of the SSPS was accomplished with a newly revised procedure which had been processed through the licensee's procedure upgrade program. Good interaction between the instrumentation and controls engineer/procedure writer and craft personnel was evident as the engineer observed the surveillance activity and solicited feedback on procedural enhancements. The inspectors considered the procedure to be of excellent quality, technically sound, and incorporating good human factors considerations. The well developed procedure, in addition to proper technician implementation, contributed to an uneventful and methodically completed SSPS test.

2MSP 1.05-I — Solid State Protection System Train 'B' Bi-Monthly Test

Instrumentation and control technicians involved with the Unit 2 train 'B' bi-monthly test of SSPS were very knowledgeable about the test and the SSPS equipment. Communications and formality during the test were excellent.

OST 1.24.3 Motor Driven Auxiliary Feed Pump Test 1FW-P-3B

On July 26, 1993, vibration readings for the motor driven auxiliary feedwater (AFW) pump were found to be greater than acceptable levels but still within the alert range. The inspector questioned the shift supervisor on the cause of the increase in vibration levels. The shift supervisor reviewed the data and recognized that the baseline vibration previously developed for the pump was incorrect. On June 25, the licensee had identified a bad vibration meter which was yielding low readings (the range scale selector switch was determined to be out of alignment). This same vibration meter was used to develop the baseline specifications for the AFW pump following pump overhaul. As corrective action to this scale misalignment, the inservice testing personnel reviewed all vibration data for each pump that the vibration meter was used on. The vibration data for these pumps were adjusted by the appropriate scaling factor. This resulted in only one additional pump (recirculation spray pump 2B) being placed on retest. However, the initial corrective action did not include determining if the bad vibration meter was used to develop any pump baseline vibration data as in the case of the AFW pump. The safety significance of this is minor since the incorrect baseline data was more conservative than the actual pump baseline data. Further review by the licensee has determined that the bad vibration meter had not been used elsewhere. Overall, the shift supervisor demonstrated good awareness of previous plant/maintenance issues (via the licensee's problem report system). However, the licensee's corrective action in response to the original meter switch misalignment was limited, as adequate follow-up could have prevented the use of incorrect vibration data.

OST 2.26.1 Turbine Throttle, Governor, Reheat Stop and Intercept Valve Test

2OST 1.12A Safeguards Protection System Train 'B' Blockable Test

The operators involved with 2OST-1.12A were very professional, used precise communications, and instituted careful self-checking techniques. Additionally, the inspectors noted that the procedure required replacement of the light bulbs in the test circuits prior to testing. The procedure did not specify what light bulbs to use. The operators used a "like-for-like" method to determine what bulbs to use. The bulbs were not Class-1E, and the operators were not sure if Class-1E bulbs were needed. The inspectors' observations were discussed with the Unit 2 Operations Manager. The Operations Manager subsequently initiated an evaluation to determine what type of light bulbs are required in the solid state protection system.

3.3 Inoperable Unit 1 Hydrogen Analyzer

On July 2, 1993, the licensee identified that the 'A' train hydrogen analyzer (H2A-1HY-101A) was inoperable due to a valve misalignment. Technical specifications require two separate and independent wide range containment hydrogen analyzers to be operable while the plant is in Mode 1 (power operation) and Mode 2 (startup). The plant entered Mode 2 on June 15, and it has been determined that the valve misalignment occurred on April 19. The 'B' train hydrogen analyzer was verified to be properly aligned and operable during this time period.

The licensee's investigation revealed that the hydrogen analyzer flowmeter flow control valves (F2 and F3) were closed following completion of surveillance testing on April 19. Surveillance procedure 1BVT 1.46.3, "Wide Range Hydrogen Monitoring System Leak Test," specified that flow valves F2 and F3 be fully opened in order to pressurize the 'A' train piping and components to 42 psig. Following the leak test, the restoration valve line-up was completed per Table 1 of BVT 1.46.3. However, this table did not specify the normal system alignment for flow meter valves F2 and F3. The test personnel realigned F2 and F3 to full shut believing this to be their original position. In actuality, the normal position of F2 and F3 was throttled open. Test personnel assumed that these flow control valves would be adjusted during the operation of the hydrogen analyzer.

As immediate corrective action, the inoperable hydrogen analyzer was calibrated, realigned, and restored to operable status. The Unit 2 hydrogen analyzers have also been verified to be properly aligned. The Unit 2 leak test does not require the flowmeter valves to be repositioned. The Unit 1 leak test procedure has been placed in an inactive status pending a procedure revision to incorporate the required throttled position of valves F2 and F3. Overall, the inspectors concluded that the safety significance of this event was very minor, as the 'B' train hydrogen analyzer was fully operable.

Plant entry to Mode 2 with only one operable hydrogen analyzer is a violation of technical specifications. However, the inspectors considered this to be of minor safety significance and considered the licensee's corrective actions to be adequate. This self-identified violation is not being cited because the criteria of Section VII.B of the Enforcement Policy were satisfied.

3.4 Unit 2 Supplemental Leak Collection and Release System (SLCRS) Actuation During Maintenance

At 9:25 a.m. on July 31, 1993, the Unit 2 SLCRS shifted to the filtered ventilation mode while instrumentation and control technicians were performing a calibration procedure on a radiation monitor (2RMR-RQI301). The technicians were replacing a lifted lead at the time of the occurrence. The lead was lifted earlier in the procedure specifically to prevent an actuation. SLCRS is supposed to shift to the filtered mode if 2RMR-RQI-301 loses power or initiates a high-level alarm (with the lead landed). Since the technicians verified the presence of power and the absence of alarms on 2RMR-RQI301, prior to landing the lead, SLCRS should not have shifted ventilation modes.

Duquesne Light Company concluded that a relay (K2) was "hanging-up" for a period of time after the monitor was powered-up, and prior to landing the lead. The relay was subsequently replaced. Additionally, Duquesne Light Company is going to change the calibration procedure to require verification of the relay's state prior to landing the lead.

During investigation of this event, Duquesne Light Company also determined that the technicians were conducting several steps of the calibration procedure out of order. This did not contribute to the event; however, it is contrary to Duquesne Light Company's policy for procedure use. The individuals involved were counselled on the use of procedures, and all other instrumentation and control technicians will be reminded of the policy.

3.5 Improper Removal of Test Equipment from a Unit 2 Pressurizer Pressure Instrument

Instrumentation and control technicians replaced a power supply card for a pressurizer pressure transmitter (2RCS-PT444) associated with pressurizer pressure control channel 2RCS*PRE21. Following replacement of the power supply, a strip-chart recorder was connected to the pressure instrument to monitor its performance. One of the monitoring functions was to measure the current output from the pressure transmitter. This was accomplished by inserting a 250 ohm resistor into the current loop and measuring voltage drop across the resistor. The recorder installation was accomplished using Corrective Maintenance Procedure 1/2 CMP 75-RECORDER-1I.

Approximately 6 days after connecting the strip-chart recorder, two instrumentation and control technicians were directed to remove the recorder. The two technicians were not involved with installation of the recorder. The technicians informed the control room of their intention to remove the recorder; however, there was no discussion of the plant conditions required for this task. When the technicians removed the 250 ohm resistor from the pressure transmitter current loop, the pressure instrument output went to zero. This caused the pressurizer spray control valves to shut and the pressurizer heaters to fully energize. Plant operators immediately recognized the problem and took manual control of pressurizer pressure. The resulting change in plant pressure was not significant (less than 20 psi).

Duquesne Light Company instrumentation and control personnel investigated the occurrence and concluded that: (1) the procedure was not adequate because it did not direct the technicians to place plant pressure control in manual prior to removing the recorder (the procedure did, however, provide appropriate direction for recorder installation); and (2) the technicians should have recognized that breaking the current loop would effect plant pressure control. To address these two issues, Duquesne Light Company is: (1) working to upgrade Corrective Maintenance Procedure 1/2 CMP 75-RECORDER-1I; and (2) going to cover the event with all instrumentation and control technicians as part of a "self-check" training review. The resident inspectors concluded that the Duquesne Light Company review of this maintenance deficiency and the planned corrective actions were adequate.

4.0 ENGINEERING (71707, 90712, 92700)

4.1 Review of Written Reports

The inspectors reviewed Licensee Event Reports (LERs) and other reports submitted to the NRC to verify that the details of the events were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspectors determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted further onsite followup. The following LERs were reviewed:

Unit 1:

93-10	Missed Technical Specification Surveillance on Safety Injection Accumulator Samples
93-11	ESF Actuation, Letdown Isolation during Unit Startup

These events were reviewed in NRC Inspection Report 50-334/93-13. The inspectors had no further questions on these events.

The above LERs were reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. Generally, the LERs were found to be of high quality with good documentation of event analyses, root cause determinations, and corrective actions.

4.2 Unit 2 Quench Spray System Timing Relay Failure

Duquesne Light Company was not able to calibrate a timing relay in the Unit 2 quench spray system (QSS) during a routine calibration procedure. The relay's function was to initiate an alarm if quench spray pump 2QSS*P21B did not establish adequate flow within 120 seconds after pump start. An exact replacement for the relay was not available because the relay is no longer manufactured, and the relays stocked for replacement were not seismically qualified. Consequently, a technical evaluation was initiated to determine if an installed spare relay, of a similar but not the same design, could be used.

The inspectors reviewed the technical evaluation report (No. 7984, Revision 0). The report concluded that the spare relay was acceptable; however, it was not obvious from the report that:

(1) the spare relay was certified Class 1E; and

(2) the decrease in timing accuracy had been fully evaluated. The report documented the effects of the decreased accuracy if the relay timed out early, but not if the relay timed out late.

The inspectors discussed the above observation with the engineer who drafted the technical evaluation report. The engineer stated that the substitute relay was Class 1E certified. The relay was being removed from an existing spare Class 1E enclosure. Additionally, he was able to show the inspectors that the change in timing accuracy would not degrade system performance. The inspectors concluded that the technical evaluation of the relay was sound, and the documentation of the evaluation was complete, except as noted above.

4.3 Unit 2 Supplemental Leak Collection and Release System (SLCRS) Surveillance Testing

The inspectors reviewed the surveillance test program for the Unit 2 SLCRS for conformance with the requirements of technical specifications (TS) and Section XI to Appendix B of 10 CFR 50, "Test Control."

The inspectors found that Duquesne Light Company had test procedures in place to address all of the TS surveillance requirements. Duquesne Light Company did not, however, have any tests which were performed on a periodic basis to ensure that the system will perform its design function, as required by Criteria XI of 10 CFR 50, Appendix B. Section 6.5.3.2.2 of the Beaver Valley Unit 2 Updated Facility Safety Analysis Report (UFSAR) states that the primary function of SLCRS is to ensure that radioactive leakage from the primary containment, following a design basis accident or radioactive release due to a fuel handling accident, is collected and filtered for iodine removal prior to discharge to the atmosphere at an elevated release point through a ventilation vent. Section 6.5.3.2.2 of the UFSAR also states that SLCRS achieves this design function by maintaining a negative pressure in the areas being exhausted. None of the Duquesne Light Company surveillance tests checked that air flow rates were satisfactory to maintain the required negative pressure in the exhausted areas following a design basis accident. A one-time test was performed in 1988 which checked the Unit 2 SLCRS air flow rates following a design evaluation which established new (reduced) flow requirements.

The inspectors discussed their findings with the SLCRS system engineer. The system engineer stated that he was going to develop a periodic test which will meet the 10 CFR 50, Appendix B requirements to demonstrate that the system will perform satisfactorily in service. He had already planned to develop such a test which will be performed during the upcoming Unit 2 refueling outage because some of the SLCRS air flows were identified as necessary to satisfy some equipment environmental qualification requirements. SLCRS testing is identified as an **unresolved item (50-412/93-01)** pending NRC review of the test procedure which is going to be developed by Duquesne Light Company.

4.4 Unit 2 Plant Safety Monitoring System (PSMS) Ventilation Filters

During a routine plant walkdown, the inspectors noted that the data processing unit cabinets for the Unit 2 PSMS had filter material attached to the ventilation ducts with tye-wraps. There were no temporary modification tags associated with this alteration. The inspectors contacted the PSMS engineer to find out how this alteration was controlled and evaluated. Specifically, the inspectors asked about: (1) the effect of the change in ventilation flow on the Class-1E qualification of the equipment; (2) how the filter media had been evaluated for this particular application; and (3) how the performance of the filters had been evaluated/maintained over time. The PSMS engineer was aware of the filters, and recalled that they were part of the original installation; however, he did not have any documentation to support their use.

Duquesne Light Company contacted Westinghouse (the PSMS vender) and obtained documentation on the use of the filters. The documentation contained an update to the PSMS technical manual containing information on the filters. Using the information from Westinghouse, Duquesne Light Company initiated a technical evaluation report which accepted the filters for use in the PSMS. Additionally, the PSMS engineer informed the inspectors that a task card would be implemented to periodically clean and inspect the filters. The inspectors concluded that Duquesne Light Company's evaluation of the filters was complete and accurate; however, the documentation should have been available following initial installation.

4.5 Unit 1 Axial Flux Difference

The inspectors reviewed the Unit 1 reactivity characteristics of the current cycle 10 core after noting a large axial flux difference as indicated on the main control board. The beginning of life axial offset (axial flux difference) was about -7 percent to -8 percent, indicative of a greater flux at the bottom of the core than at the top of the core. The axial flux offset was within the technical specification average axial flux target of -7.9 percent (±7 percent target band) for 100 percent power. The inspectors were informed that this condition was due to extended reduced power operation with rods fully withdrawn during the previous fuel cycle. Unit 1 operated at about 90 percent power for 7 months for fuel cycle extension and high main unit generator end turn vibrations. The reactor engineering group has provided the operators with a graph of predicted axial offset vs. core burnup. The axial offset is predicted to become more positive (by 6.5 percent) after the core has achieved a burnup of 2,000 MWD/MTU. After August 17, 1993, the axial flux offset began to trend positive as predicted. Overall, the inspectors concluded that the reactor engineers were providing good support to plant operations in explaining and predicting the behavior of the core so that reactor operators were able to monitor and understand the changes in core characteristics.

5.0 PLANT SUPPORT (71707, TI 2500/28)

5.1 Radiological Controls

Posting and control of radiation and high radiation areas were inspected. Radiation work permit compliance and use of personnel monitoring devices were checked. Conditions of step-off pads, disposal of protective clothing, radiation control job coverage, area monitor operability and calibration (portable and permanent), and personnel frisking were observed on a sampling basis. The inspectors had the following observations:

(1) Health physics personnel maintained good coverage and control of a decontamination effort in the 710 foot level of the Unit 2 primary auxiliary building.

(2) Several cases of unsecured lines (hoses, electric cords, etc.) running between contaminated and non-contaminated areas were noted. This is a poor practice which can lead to the spread of contamination outside of contamination areas. Station radiological controls procedures recommended securing or marking the lines if possible.

(3) The Unit 2 liquid waste discharge lines, which run through the turbine building, were not marked in any way. The lines should have been labeled to indicate the presence of internal contamination, to prevent inadvertent opening without proper radiological controls.

The inspectors observations were presented to radiological controls personnel. The issues involving unsecured lines and liquid waste line labeling were promptly resolved.

5.2 Security

Implementation of the physical security plan was observed in various plant areas with regard to the following: protected area and vital area barriers were well maintained and not compromised; isolation zones were clear; personnel and vehicles entering and packages being delivered to the protected area were properly searched and access control was in accordance with approved licensee procedures; persons granted access to the site were badged to indicate whether they have unescorted access or escorted authorization; security access controls to vital areas were maintained and persons in vital areas were authorized; security posts were adequately staffed and equipped, security personnel were alert and knowledgeable regarding position requirements, and that written procedures were available; and adequate illumination was maintained. Licensee personnel were observed to be properly implementing and following the Physical Security Plan

5.3 Emergency Preparedness

5.3.1 Emergency Response Facility Operability

The loss of power event to the emergency response facility (ERF) on August 18, 1993, at 2:45 a.m. resulted in a loss of power to the emergency operating facility (EOF). The EOF is part of the licensee's emergency assessment capability during accident conditions. To assess the operability of the ERF, the licensee had previously developed a logic guide to address the following factors: ability to activate the ERF staff; ability to perform dose assessment; habitability; and plant data acquisition storage and retrieval. This logic guide is contained within the control room standing night orders. The licensee's emergency preparedness organization determined the ERF to be inoperable at about 8:30 a.m., based on a loss of ERF habitability. The ERF computers for plant data acquisition were also inoperable, but communications lines for plant data transfer between the control room and the ERF were maintained. These conditions did not, however, result in a loss of emergency assessment capability, since the licensee maintains an alternate EOF at the Joint Public Information Center. The operability of the alternate EOF was verified by licensee personnel. The inspectors discussed the acceptability of the alternate EOF with Region I specialists and concluded that the licensee's evaluation was correct. Power to the ERF was restored by 11:30 a.m.

During the inspectors' review of this event, it was noted that the nuclear shift supervisor did not use the ERF operability logic guide. The inspectors discussed this with the Emergency Preparedness Manager and were informed that the shift supervisor instead focused on the 10 CFR 50.72 reporting requirements for emergency assessment capability. The ERF operability guide was not used until questioned by the Unit 1 operations manager. The licensee's emergency preparedness organization also recognized the failure to use the ERF operability guide and has initiated action to strengthen its visibility and use. This oversight was minor as there was no loss of emergency capability. The emergency preparedness staff demonstrated good support in verifying the emergency assessment capability of the station.

5.4 Housekeeping

Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards. The inspectors conducted detailed walkdowns of accessible areas of both Unit 1 and Unit 2. Housekeeping at both units was generally acceptable; however, the inspectors continued to note deficiencies in the control of transient material. Each of the deficiencies was promptly corrected, and the inspectors have noted increased management attention to the control of transient material. Several deficiencies found by the inspectors were of greater significance. Housekeeping in the 710 foot level of the Unit 2 primary auxiliary building between the demineralizers was particularly poor. A significant amount of tools, hoses, anti-contamination clothing, etc., was in the area even though no maintenance was in progress. This area was subsequently cleaned up. A box of light bulbs was found inside a Unit 2 protection system cabinet during 2OST 1.12A. An operator removed the box. The licensee is continuing to follow-up on storing items inside cabinets.

5.5 Employee Concerns Program

The inspector performed a review of the licensee's quality concern resolution program to determine the characteristics of the program. Various aspects of the licensee's program were recently inspected in November 1992 (see NRC Inspection Reports 50-334, 412/92-20), and included program scope, independence, confidentiality, and feedback. No programmatic changes have occurred since the inspector's original review. Attachment 'A' to the current inspection report contains a survey of the licensee's employee concerns program completed by the inspector.

5.6 Posting of NRC Notice to Workers

When NRC recently re-issued NRC Form 3, "Notice to Employees," the inspectors compared Duquesne Light Company's posting of notices to workers to the requirements of 10 CFR § 19.11 and 10 CFR § 50.7(e). The inspectors found that the licensee's NRC Form 3 postings were not satisfactory. The forms had been reduced from 17 inches by 11 inches to 8½ inches by 11 inches, and were not completely legible. Duquesne Light Company was informed of the inspectors' finding. Duquesne Light Company immediately made new 8½ inch by 11 inch copies of the forms. This time, the forms were legible; however, the inspectors questioned the 50 percent size reduction. Additionally, the inspectors questioned the method of posting. 10 CFR § 50.7(e) requires that the NRC Form 3 be posted such that it can be observed by employees on their way to or from their place of work. Duquesne Light Company placed each NRC Form 3 in a stack of other postings with a cover sheet titled, " Federal and State Postings."

NRC considers that up to a 25% reduction is allowed, as long as it is easily readable, easily noticeable as an NRC Form 3, and in plain view of those passing by. Not posting NRC Form 3 in plain view (*i.e.*, behind a stack of other postings) is a violation of 10 CFR § 19.11(c) and 10 CFR § 50.7(e). Duquesne Light Company committed to change their postings to conform to the regulations. They did, however, state that changing the method they have used to post the NRC Form 3 is a regulatory burden and adds little to the usefulness of their present method of posting when considered together with related information provided in site training programs.

The inspectors considered this to be of minor safety significance and considered the licensee's planned corrective actions to be adequate. This violation is not being cited because the criteria of Section VII.B of the NRC Enforcement Policy were met.

5.7 Emergency Diesel Generator Jacket Water Chemistry

The inspectors performed a review of the Unit 1 emergency diesel generator (EDG) jacket water chemical analysis following notification of glycol-water cooling deficiencies at other nuclear facilities. The use of a glycol-water mixture (anti-freeze) for jacket water cooling in General Motors (Electro-Motive Division) EDGs may lead to potential hot spots in the cylinder head and cause cracking of the head. The use of a glycol-water mixture will result in derating the engine capacity by 5 percent. Unit 1 maintains two General Motors (EMD-645) diesel generators while Colt-Pielstick EDGs are installed at Unit 2. The inspector found the licensee to be correctly applying the recommendations of the vendor technical manual (maintenance instruction 1748) with respect to jacket water chemistry. The EDGs are maintained in a heated building and use only a borate-nitrite solution as a corrosion inhibitor. This corrosion inhibitor was being maintained within proper specifications for pH level and concentration.

6.0 ADMINISTRATIVE

6.1 Preliminary Inspection Findings Exit

At periodic intervals during this inspection, meetings were held with senior plant management to discuss licensee activities and inspector areas of concern. Following conclusion of the report period, the resident inspector staff conducted an exit meeting on August 31, 1993, with Beaver Valley management summarizing inspection activity and findings for this period.

6.2 Attendance at Exit Meetings Conducted by Region-Based Inspectors

During this inspection period, the inspectors attended the following exit meetings:

Dates	Subject	Inspection Report No.	Reporting Inspector
7/23/93	Open Items and Procurement	93-14/15	A. Finkle
7/30/93	Solid Radwaste and Transportation	93-15/16	J. Nick
8/13/93	Effluents and Chemistry	93-17/18	J. Jang
8/13/93	Security	93-18/19	G. Smith

6.3 NRC Staff Activities

Inspections were conducted on both normal and backshift hours: 34 hours of direct inspection were conducted on backshift; 3 hours were conducted on deep backshift. The times of backshift hours were adjusted weekly to assure randomness.

R. Barkanic, Nuclear Engineer, Pennsylvania Department of Environmental Resources (DER) visited the site and accompanied the transportation and security inspections during the weeks of July 26 and August 9.

G. Edison and W. Butler visited the site and the inspectors on August 5 and 6 for discussions with the inspectors, to attend an Offsite Review Committee meeting, and to tour the site.

ATTACHMENT A

EMPLOYEE CONCERNS PROGRAMS

PLANT NAME: Beaver Valley 1&2 **LICENSEE:** Duquesne Light Company
DOCKET #: 50-334; 50-412

NOTE: Please circle yes or no if applicable and add comments in the space provided.

A. PROGRAM:

1. Does the licensee have an employee concerns program? **(Yes or No/Comments)**

   Yes.

2. Has NRC inspected the program? Report # **92-20/20; 90-06/07**

B. SCOPE: (Circle all that apply)

1. Is it for:

   a. Technical? **(Yes, No/Comments)**

      Yes.

   b. Administrative? **(Yes, No/Comments)**

      Activities including but not limited to quality assurance, safety related, security, or personnel/management issues.

   c. Personnel issues? **(Yes, No/Comments)**

      Yes.

2. Does it cover safety as well as non-safety issues? **(Yes or No/Comments)**

   Yes.

3. Is it designed for:

   a. Nuclear safety? **(Yes, No/Comments)**

      Yes.

   b. Personal safety? **(Yes, No/Comments)**

      No, licensee maintains a separate program for industrial safety concerns.

   c. Personnel issues - including union grievances?
      (Yes <u>or</u> No/Comments)

      Yes, the assistancc of human resources personnel may be solicited.

4. Does the program apply to all licensee employees?
   (Yes <u>or</u> No/Comments)

   Yes, including past employees.

5. Contractors?
   (Yes <u>or</u> No/Comments)

   Yes.

6. Does the licensee require its contractors and their subs to have a similar program?
   (Yes <u>or</u> No/Comments)

   No.

7. Does the licensee conduct an exit interview upon terminating employees asking if they have any safety concerns?
   (Yes <u>or</u> No/Comments)

   No, exit interviews are conducted through the human resources department.

C. INDEPENDENCE:

1. What is the title of the person in charge?

   Manager, Quality Services Unit is designated as the program sponsor.

2. Who do they report to?

   Senior Vice President and Chief Nuclear Officer of the Nuclear Power Division

3. Are they independent of line management?

   Yes.

4. Does the ECP use third party consultants?

   Funding is budgeted for this contingency; however, this has not been necessary to date.

5. How is a concern about a manager or vice president followed up?

   Investigation may be completed by the licensee's Independent Safety Evaluation Group (ISEG), Duquesne Light personnel outside the Nuclear Power Division, or third party consultants (non-Duquesne Light employees).

D. RESOURCES:

1. What is the size of the staff devoted to this program?

   Two cognizant individuals who report to the Manager, Quality Services Unit. However, any member of the Quality Services Unit may be called upon to conduct an investigation.

2. What are ECP staff qualifications (technical training, interviewing training, investigator training, other)?

   Since any Quality Services individual may be involved, a wide range of expertise/qualifications are available to choose from. This includes personnel with technical backgrounds and personnel who have received interview training.

E. **REFERRALS:**

1. Who has followup on concerns (ECP staff, line management, other)?

   ECP staff; the allegations are not closed out until all corrective actions regarding the concern are completed.

F. **CONFIDENTIALITY:**

1. Are the reports confidential?
   (Yes or No/Comments)

   Yes, also all records are considered proprietary.

2. Who is the identity of the alleger made known to (senior management, ECP staff, line management, other)?
   (Circle, if other explain)

   ECP staff and Manager Quality Services.

3. Can employees be:

   a. Anonymous? **(Yes, No/Comments)**

      Yes.

   b. Report by phone? **(Yes, No/Comments)**

      Yes, licensee maintains a 24-hour hotline. Mail-in forms are also posted in nine locations throughout the plant.

G. **FEEDBACK:**

1. Is feedback given to the alleger upon completion of the followup? **(Yes or No - If so, how?)**

   The investigative report, as well as final disposition of the concern, are forwarded to the alleger and Senior Vice President.

2. Does program reward good ideas?

   No, this is not the purpose of the licensee's ECP program. A separate employee suggestion program is in place.

3. Who, or at what level, makes the final decision of resolution?

   The program sponsor, Manager, Quality Services Unit. However, the Senior Vice President may override the final decision of resolution.

4. Are the resolutions of anonymous concerns disseminated?

   The final report is forward to the Senior Vice President.

5. Are resolutions of valid concerns publicized (newsletter, bulletin board, all hands meeting, other)?

   No.

H. EFFECTIVENESS:

1. How does the licensee measure the effectiveness of the program?

   There is no formal mechanism for this; however, the ISEG has recently performed an independent review of the program at the request of the Senior Vice President.

2. Are concerns:

   a. Trended? **(Yes or No/Comments)**

      No.

   b. Used? **(Yes or No/Comments)**

      Corrective action is taken in response to substantiated concerns.

3. In the last three years how many concerns were raised? 7 Of the concerns raised, how many were closed? 7 What percentage were substantiated? **43%** (3/7)

4. How are followup techniques used to measure effectiveness (random survey, interviews, other)?

   The Manager, Quality Services Unit, has conducted an anonymous survey regarding the reporting of plant related safety concerns (with respect to having no reservations of reporting).

5. How frequently are internal audits of the ECP conducted and by whom?

   Internal Audits are not conducted.

I. ADMINISTRATION/TRAINING:

1. Is ECP prescribed by a procedure? **(Yes or No/Comments)**

   Yes; Nuclear Power Division Administrative Procedure 8.14 and Quality Services Procedure 16.4.

2. How are employees, as well as contractors, made aware of this program (training, newsletter, bulletin board, other)?

   -- **Initial site access**
   -- **Annual refresher training**
   -- **Posted bulletin boards**
   -- **Memos from the Senior Vice President and Quality Services Manager to all employees and contractors**
   -- **Closed circuit TV**

ADDITIONAL COMMENTS: **(Including characteristics which make the program especially effective, if any.)**

NAME: **TITLE:** **PHONE #:**
Pete Sena / Resident Inspector / (412) 643-2000 **DATE COMPLETED:** 8/20/93

ITEMS CONT.? (Y/N) N