U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.	92-24
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:	October 13 - November 18, 1992
Inspectors:	Lawrence W. Rossbach, Senior Resident Inspector Peter P. Sena, Resident Inspector

Approved by: John Rogge 12/1/92
John F. Rogge, Chief — Date
Reactor Projects Section No. 4B

Inspection Summary

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

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EXECUTIVE SUMMARY

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Plant Operations
Unit 1 startup activities, following the reactor trip on October 9, 1992, were conducted in a safe and deliberate manner. Excellent operator performance was evident during a Unit 1 feedwater transient. Prompt and appropriate operator action averted the need for an automatic turbine trip/reactor trip.

Radiological Controls
Licensee's controls during a spent fuel pool cleanup project were found to be adequate. Those controls prevented a worker from receiving an excessive exposure when a fuel assembly nozzle was inadvertently lifted to within 3.5 - 5.0 feet of the water surface.

Maintenance and Surveillance
Switchyard maintenance was well planned and coordinated. The licensee's safety precautions and contingency plans were commensurate with those discussed in recent NRC information notices. A technician's error during the performance of a Unit 1 monthly surveillance testing resulted in overfeeding the 'A' steam generator to 68%. The safety significance of this event was minor as prompt operator actions restored level to within the programmed band before the feedwater isolation/turbine trip setpoint of 75% was reached.

Security
The security force transition from Security Bureau, Incorporated, to Burns International Security Services has gone smoothly as the licensee's performance continues to be excellent.

Engineering and Technical Support
The replacement of the Unit 1 plant process computer represents a significant management commitment towards upgrading existent plant equipment. The impact of the computer replacement on plant operations was thoroughly evaluated and minimized. The 1992 annual fire drill with the local volunteer fire departments was not well coordinated as several drill deficiencies were evident.

Safety Assessment/Quality Verification
A thorough review of assumptions for a safety assessment by the licensee identified that the steam driven auxiliary feedwater pump auto start signals for both units came from non Class 1E relays. This was acceptably resolved by a circuit modification for Unit 1 and a basis for continued operation for Unit 2. The use of non 1E relays to provide the reactor coolant pump bus undervoltage and underfrequency reactor trip signals was also found acceptable based on having adequate diverse trip signals.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 was in cold shutdown at the beginning of this inspection period while repairs to a reactor coolant pump motor were completed. The unit was brought critical on November 1, following completion of this motor repair, and operated at 90% power from November 2 throughout the remainder of this inspection period. The utility operates Unit 1 at 90% power and makes periodic load reductions to accommodate lower system demands.

Unit 2 operated at full power through this inspection period without any significant operational events.

2.0 PLANT OPERATIONS (71707, 93702)

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: low head safety injection, recirculation spray, and quench spray. 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
- Safeguard Areas
- Service Buildings
- Turbine Buildings
- Intake Structure
- Yard Areas
- Containment Penetration Areas
- Unit 1 Containment 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 were 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.

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 acceptable.

2.2 Unit 1 Reactor Coolant Pump Failure

At the beginning of the inspection period, the licensee had removed the faulted 'A' reactor coolant pump (RCP) motor from containment for shipment to Westinghouse. The RCP motor fault previously resulted in a reactor trip on October 9, 1992 (see NRC inspection report 92-20). Visual inspection of the stator indicated that a localized turn to turn type insulation failure had occurred. Westinghouse performed a splice repair instead of a complete motor rewind since the damage was localized in a top half coil. In parallel with the repair effort, the licensee explored the possibility of obtaining a spare motor from other nuclear facilities. Westinghouse completed the repairs and returned the stator to Beaver Valley on October 19. Westinghouse investigated the cause of the RCP failure but was unable to identify the most likely cause. Since the motor had been running for 317 consecutive days, failure due to an incoming voltage surge was not likely. There was also no indication of thermal aging. Westinghouse concluded that the motor failure was a random event due to accelerated insulation aging caused by unknown factors.

Following the reassembly of the RCP motor, the inspector reviewed the post-maintenance test run data. No deficiencies were noted as indicated by the A, B, and C phase current and the unbalanced current. The inspector observed the recovery of the 'A' reactor coolant system loop (refill, heatup, and opening of the loop isolation valves), mode changes, and startup operations. The inspector observed excellent operator performance, including strict procedural compliance, well disciplined command and control, and controlled operation of plant equipment. Additional senior reactor operators (SROs) assisted the on-shift nuclear shift supervisor in verifying that all prerequisites, such as maintenance work request closeout, were satisfied. This in turn allowed the on-shift SROs to more fully concentrate on the operation of the plant. Overall, the startup activities were conducted in a safe and deliberate manner.

2.3 Unit 1 Feedwater Transient

On November 13, 1992, Instrumentation and Controls (I & C) technicians were performing a monthly surveillance on the Unit 1 'B' steam generator narrow range level indicator when a technician error caused a feedwater transient. The maintenance aspects of this event are discussed in Section 4.4. The technician had inadvertently removed the level control signal

for the 'A' steam generator which resulted in a full open demand signal to the 'A' feedwater control valve (FCV). At the time of the event, the plant was operating at 90% power, and the 'A' FCV was in automatic control with an open demand signal of about 50%. As indicated by the sequence of events recorder, annunciators in the control room alarmed within three seconds of the error indicating 'A' steam generator level deviation from setpoint and abnormal 'A' feedwater flow greater than steam flow. The operator immediately recognized that feedwater flow was "pegged high" on the indicator and that a full-open demand signal existed on the 'A' FCV. The operator immediately placed the 'A' FCV in manual control and reduced the open demand signal from the benchboard. Steam generator level had increased from 44% to 68% in about 30 seconds before the operator was able to restore level to within the programmed band. The inspector reviewed the sequence of events recorder and steam generator level strip chart and noted that level was rapidly approaching the trip setpoint of 75% and would have resulted in a feedwater isolation and turbine trip/reactor trip within several seconds. The inspector concluded that prompt and correct operator action averted the need for an automatic reactor trip and exemplified the excellent operator performance during this event.

3.0 RADIOLOGICAL CONTROLS (71707)

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. Licensee personnel were observed to be properly implementing their radiological protection program.

3.1 Spent Fuel Pool Cleanup

The licensee has initiated a Unit 1 spent fuel pool cleanup project to remove non-fuel bearing irradiated waste components. These components include, for example, thimble plugs, burnable poison rod assemblies, and incore detectors. The project scope includes the identification and inventory of irradiated hardware, dose profiling, storage of components into a disposal container (liner), and disposal liner loading into a transportation cask for offsite burial. On October 22, 1992, during the direct characterization of the waste, a Hi-Hi radiation alarm was received on the fuel bridge radiation monitor RM-207 (alarm setpoint: 15 mRem/hr). Two of the four portable area radiation monitors located within the work area also alarmed (alarm setpoint: 100 mRem/hr). The inspector reviewed this event to determine if the licensee's exposure controls were sufficient to have prevented an overexposure to the workers involved.

During the waste characterization process, the licensee used a gamma ray scanning device to determine the nuclide concentration of the irradiated hardware. Also, an underwater high radiation survey instrument (RO-7) was used for radiation dose profiling. During this process, the irradiated hardware was grappled and moved underwater manually via a stainless

steel cable toward the RO-7 for dose rate measurements. As a general work practice, each hardware movement was monitored by a health physics technician. During the incident on October 22, the work party leader requested that the RO-7 underwater monitor be relocated from the crane bridge to the deep pit of the spent fuel pool in order to perform a survey of a fuel bundle bottom support nozzle. However, this action was inadequately communicated as the instructions were misunderstood by a second supervisor. Instead, the worker was instructed to reposition the bottom nozzle to the RO-7 for the dose rate survey as per previous practice. The nozzle was initially about 10 feet under water. The worker was aware that he was repositioning the nozzle and that a minimum depth of 6 feet of water should be maintained. As the nozzle was being repositioned, the worker attempted to maneuver the component around a second cable that was in the intended path of travel. At this time, radiation levels increased and two portable and the fuel bridge area radiation monitors alarmed. The worker's digital alarming dosimeter (DAD) also alarmed (alarm setpoint: 500 mRem/hr). The worker immediately recognized that the item he was positioning had caused the alarm and lowered the nozzle further into the pool. Area radiation levels returned to normal and were confirmed by follow-up surveys.

The licensee conducted a dose assessment of the individuals involved. The worker's digital alarming dosimeter indicated that he received a whole body exposure of 5 mRem over the entire shift. He was, however, in a radiation field of 6.3 R/hr for about two seconds based on the dose and dose rate measured by the DAD. The worker's TLD indicated he received a whole body dose of 14 mRem between October 1 and October 22. The dose rate from the nozzle assembly ranged between 6,000 - 9,000 R/hr on contact. The licensee estimated that the nozzle came within between 3.5 - 5.0 feet of the water surface. No other individuals involved received any measurable exposure during this incident.

The licensee had established radiation protection controls to protect workers involved in this project. The inspector reviewed NRC Information Notice 90-33, "Sources of Unexpected Occupational Radiation Exposure at Spent Fuel Storage Pools," to determine if the licensee's controls were commensurate with those discussed in the notice. Licensee controls included, in part: the establishment of a hot-particle zone; measures to ensure that irradiated components are not left suspended under water from the pool handrail; measures to prevent radiation streaming; and the use of alarming portable area radiation monitors and personnel digital alarming dosimeters. The inspector also reviewed the licensee's basis for the RM-207 alarm setpoint of 15 mRem/hr. Calculations indicated that with six feet of water shielding and with the RM-207 one foot above the water surface, a component would have to read 88,000 R/hr on contact to set off the alarm. The licensee did not anticipate handling any component with contact dose rates greater than 20,000 R/hr. The inspector concluded that the RM-207 setpoint was appropriate and conservative. Additionally, the inspector concluded that the licensee's enhanced use of area radiation monitors and personal alarming dosimeters as well as ALARA briefings prevented the worker from receiving an excessive exposure.

NRC Information Notice 90-33 also states that measures should be established to ensure that highly radioactive objects stored under water at one end of a line, whose other end is secured above the surface of the pool, are not unexpectedly pulled to the surface. Licensee procedure ITOP-92-12, "Spent Fuel Pool Cleanup Project," states that irradiated components should be controlled to maintain a distance of six feet below the surface of the spent fuel pool. Even though the wrong item was moved during this incident as a result of miscommunications, the worker was aware he was handling irradiated hardware. The inspector concluded that additional controls could have prevented the nozzle assembly from coming less than six feet from the water surface. For example, the nozzle was repositioned without being directly monitored by a health physics (HP) specialist. At the time of the incident, the radiation protection supervisor was outside the spent fuel building assisting in the decontamination of an individual while the radiation technician was monitoring a separate activity in the pool. Previous component movements were monitored as a general work practice, but not as a specific radiation work permit (RWP) requirement. The licensee has subsequently amended the RWP to read, "HP personnel shall be present to continuously monitor dose rates at the water surface during movement of any item in or under water." Additionally, the inspector noted that no visual references were available to provide indication of six feet of water depth. The refraction of light across the water surface can make it very difficult for a worker to judge six feet of water unless a visual reference or depth marker is provided. The licensee has evaluated this comment and subsequently installed lanyards in the pool with a six-foot marker attached. These measures now in place will provide additional defense in depth controls for worker protection.

The inspector concluded that this incident was of minor safety significance, but did have the potential to result in excessive exposure/overexposure to workers. Overall, the licensee's controls were adequate as they did limit the worker to an exposure of only 5 mRem during the shift. However, the licensee's controls could have been improved by having a radiation technician monitor each hardware movement per an RWP requirement as well as providing workers with a visual depth marker.

4.0 MAINTENANCE AND SURVEILLANCE (62703, 61726, [illegible]7)

4.1 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.

Maintenance activities reviewed included:

MWR 13826	Replace seats on chemical addition ball valve 2QSS-249
MWR 04003	Replace chips U3 through U11 on waste handling area detector 2RMJ-DAU204
MWR 13760	Install Design Change 1930 in Train 'A' Solid State Protection System (see Section 7.2)

The inspector noted that the personnel involved with design change 1930 were knowledgeable, maintenance procedure quality was good, and the proper quality control oversight existed. The inspector also observed active participation by maintenance supervisors.

4.2 Switchyard Maintenance

On November 16, 1992, the licensee initiated pre-planned maintenance activities within the 138 kilovolt (KV) switchyard area. This maintenance required that one of the two offsite power supplies for each unit be deenergized for a short period. Technical Specification 3.8.1.1.a requires that two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system be operable. The allowed outage time for this limiting condition for operation (LCO) is 72 hours. Due to the safety significance of removing an offsite power supply from service for maintenance (*i.e.*, LCO maintenance), the inspector performed a review of the adequacy of the licensee's maintenance plan, safety precautions, and contingency plans.

The maintenance involved the replacement of the existing Z-30 line breaker, oil circuit breaker OCB85, with an upgraded design equivalent breaker manufactured by Siemans Corporation. The Z-30 line supplies the Unit 2 system station service transformer 2A via OCB 85 from either 138 KV bus 2 or the Midland Substation. The four system station service transformers supply each unit Class 1E electrical system when the unit main generator is off line. The existing breaker (OCB 85) will be used as a maintained spare for the other three offsite power supply breakers since the utility does not have a spare, and an exact replacement is no longer available from the original vendor. Due to the clearance points associated with the breaker removal, installation, and testing, the licensee planned on three separate outages in which an offsite power supply would be removed from service. On two occasions, the Unit 2 transformer 2A would be out of service, and on one occasion, the

Unit 1 transformer 1B would be out of service. The licensee has designated this maintenance activity an "Infrequently Performed Test and Evolution," (IPTE) per Nuclear Group Administrative Procedure 8.23. The IPTE procedure provides guidance for the conduct of the evolution, the degree of management involvement, and establishes management's expectations. The licensee does not routinely perform maintenance of this nature which results in voluntary entry into a LCO action statement. The Unit 2 Operations Manager was designated as the responsible test manager.

Prior to establishing the first Z-30 line clearance, the licensee verified the operability of the four station emergency diesel generators (two per unit) by performing the monthly full-load surveillance tests. Also, prior to removing a unit system station service transformer from service, the licensee completed an engineered safety features (ESF) clearance checklist. This checklist is used to ensure that all redundant train components are available. During the periods in which an offsite power supply circuit was removed from service, the licensee restricted all maintenance on the opposite train to ensure equipment availability.

The inspector attended the prejob briefing between Beaver Valley management and the Duquesne Light Company District Substation personnel. This briefing highlighted the day-to-day job description, necessary coordination between Substation and Beaver Valley personnel, and emergency actions to be taken in case of a unit trip while an offsite power supply is removed from service. The licensee satisfactorily addressed the concerns raised by the inspector involving the switchyard maintenance. NRC Information Notice 91-81, "Switchyard Problems that Contribute to Loss of Offsite Power," highlighted difficulties associated with authority over the switchyard under emergency conditions. At the Vermont Yankee nuclear facility, the restoration of offsite power was delayed because of lack of communications between the plant staff and switchyard personnel. The Beaver Valley IPTE project manager was designated as having authority over the switchyard during emergency conditions. A "traveling operator," with appropriate communications equipment, was assigned to the switchyard during the outage periods. The traveling operator acts as the focal point between Substation and Beaver Valley personnel if Beaver Valley determines they need the Z-30 line or 138 KV bus 2 returned to service. Communications would still be directed through the load dispatcher. Contingency plans were in place for restoring the Z-30 line or the 138 KV bus 2 to service. The licensee estimated that the maximum time for circuit restoration would be 1.5 hours if necessary. NRC Information Notice 92-13, "Inadequate Control over Vehicular Traffic at the Nuclear Power Plant Sites," informed licensees of continuing problems of vehicular traffic near safety systems resulting in loss of offsite power events. The inspector observed that the licensee had proper control of vehicles within the switchyard. All non-designated work areas were roped off, and designed traffic lines were established. All vehicle backing operations were conducted with the assistance of spotters. Positive control over the entry of vehicles and personnel into the switchyard was maintained by the licensee.

Overall, the inspector concluded that this maintenance resulted in a net safety benefit due to the improved reliability of the offsite transmission network. The maintenance was well

planned as proper precautions, contingencies, and prerequisites were established prior to commencing the line outage. Use of the IPTE process ensured an appropriate level of management attention was focused on the successful completion of the job well within the outage time allowed by the limiting condition for operation. Excellent interface and coordination were demonstrated between the Beaver Valley and Substation personnel.

4.3 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 following operational surveillance tests (OSTs) and temporary operating procedures (TOPs) were reviewed:

1TOP 91-06	Quench Spray Chemical Injection Pumps (1QS-4A, B, C, D) Flow Rate Verification
OST 1.12C	Safeguards Protection System Train 'B' Containment Isolation Phase B/Spray Actuation Test
OST 1.24.4	Steam Driven Auxiliary Feed Pump Test (1FW-P-2)
OST 1.24.8	Motor Driven Auxiliary Feed Pumps (1FW-P-3A, 3B) Check Valves and Flow Test
OST 2.13.4	Recirculation Spray Pump 2RSS-P21B Dry Test
OST 2.36.1	Emergency Diesel Generator 2EGS-EG2-1 Monthly Test
OST 2.36.2	Emergency Diesel Generator 2EGS-EG2-2 Monthly Test

No significant problems were noted during the conduct of these surveillances. These surveillances were properly controlled and documented.

4.4 Technician Error During Surveillance Testing

During the performance of a monthly surveillance test on the Unit 1 'B' steam generator narrow range water level channel, a human error resulted in a transient on the feedwater system. However, prompt licensed operator action averted the need for an automatic reactor trip. The inspector reviewed this event and attended the licensee's critique to determine its safety significance and root cause.

Instrumentation and control technicians were performing Maintenance Surveillance Procedure (MSP)-24.06, "L-1 FW486 Loop 2 Narrow Range Steam Generator Level Channel III Test." This surveillance calibrates the level comparators associated with the low-low level reactor trip/auxiliary feedwater start and the high level turbine trip/feedwater isolation signal. The feedwater control valve to the 'B' steam generator (FCV-1FW-488) was placed in manual control while the channel was in test. During the test equipment setup, a transmitter simulator was connected to test jack TJ-486 to allow the input of level test signals. The following procedural step instructed the technician to "place the signal injection test switch CT-486 in the up (test) position." However, the technician incorrectly placed the adjacent test switch, CT-476, in the test position. Both switches were correctly labeled. This error removed the level control signal for the 'A' steam generator. The steam generator water level control system automatically responded by demanding a full-open signal to the 'A' FCV. The technician recognized his error when he was unable to adjust the transmitter simulator. The technician subsequently restored test switch CT-476 to its normal position in about 30 seconds. Prompt action by the licensed reactor operator in the control room prevented steam generator level from reaching the turbine trip/feedwater isolation signal setpoint of 75%.

The inspector reviewed the procedure and noted that no procedural deficiencies existed. Specifically, the format was consistent with the standard procedure upgrade format, the instructions were clear, equipment identification was correct, and the procedural step in question contained only one action. The inspector also observed the interior of the protection rack and concluded that the error did not result from poor human factors engineering such as poor man-machine interface (labeling deficiencies, equipment arrangement), or poor work environment. The inspector agreed with the licensee's conclusion that human error was the cause of incorrectly following the procedure and that proper self-checking, as per recent training, could have prevented the error. Overall, this event had minor safety significance as operator action averted the need for a reactor protection system actuation.

5.0 SECURITY (71707)

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.

As described in previous NRC inspection reports 92-20/20 and 92-21/21, a contract to provide the site security force was awarded to Burns International Security Services on September 30, 1992. Burns replaces Security Bureau, Incorporated. Transition to Burns International was completed during this inspection period. The guard force and supervisors were largely unchanged by the change in contractors because all active Security Bureau, Incorporated guards and supervisors were offered employment with Burns International. The transition was, therefore, mainly administrative. The transition went smoothly. The excellent performance of the security force continued and appeared unaffected by the new contract.

6.0 ENGINEERING AND TECHNICAL SUPPORT (2515/94, 37828, 7'707)

6.1 (Closed) PWR Moderator Dilution TI 2515/94

Previous licensee and NRC assessments concluded that no additional licensee actions were required with regard to the moderator dilution issue. The previous NRC project manager's review of this issue dated May 12, 1988, concluded that there were no paths whereby a boron dilution event could occur, other than those already analyzed in the Unit 1 and 2 Final Safety Analysis Reports and that the concerns of TI 2515/94 did not apply to this site. The inspector verified with the current NRC project manager that the previous project manager's assessment in this area was still acceptable. This item is closed.

6.2 Unit 1 Plant Computer Replacement

On November 6, 1992, the licensee implemented a design change to replace the Unit 1 P-250 in-plant computer. The P-250 is a 1968 vintage computer used for process monitoring. The new computer has numerous advantages over the P-250. Improvements include: extensive use of on-line system diagrams with associated temperature, pressure, and flow parameters; expansion capability; improved data scan frequency; human factors engineering for operator interface; visual data trending; and programmed surveillance capabilities such as continuous thermal power monitor. The computer replacement was being performed while the unit was operating at 90% power. The inspector reviewed the design change package (DCP 1812) to ensure that the impact on plant operations was sufficiently evaluated by the licensee.

The data obtained from the P-250 is used for several operational surveillance tests. These include, for example, reactor coolant system leak rate calculations and daily heat balance calculations. Prior to removing the P-250 from service, the licensee established an alternate means of data collection for interim monitoring (temporary modification 1-92-12). A data logger (Chessell 4200 processing recorder) was placed in service and calibrated for the points to be monitored. The inspector reviewed the applicable surveillance procedures to ensure that all computer points needed for the surveillances were available on the data logger. The inspector also compared the parameters logged by both the P-250 and the Chessell for accuracy. The final surveillance calculations were also compared based on the two sources of data. The required computer points and calibrations were previously verified by licensee

computer engineers and senior reactor operators. No discrepancies were noted by the inspector. The licensee established a 31-day window for completing the design change. This was due to the use of the P-250 for several technical specification surveillance requirements that are performed every 31 effective full power days. These tests include flux mapping, delta flux target update, and critical boron concentration. The licensee completed these tests prior to removing the P-250 from service. The licensee also established alternate monitoring of these points to be used if needed.

The licensee also evaluated the impact the computer replacement would have on other instrumentation. The replacement project did not affect either the availability or operation of the sequence of events recorder, the inadequate core cooling monitor (ICCM), or the plant variable computer (PVC). The PVC monitors plant data to permit the assessment of plant conditions, including accident monitoring. The impact on the safety parameter display system was minimal and only involved core exit thermocouple information for one minute during a power supply transfer. Thermocouple date was still available on the ICCM during this time. Two alarm functions, axial flux difference and rod deviation, were provided by the P-250. However, due to previous program problems with the P-250, these functions were already being logged by hand.

The inspector concluded that the installation of the new computer represents a significant management commitment toward upgrading existing plant equipment and improving plant/operator performance. The design change package and associated safety evaluation were thorough and detailed. The early involvement of licensed operators in the development and implementation of this project significantly contributed to minimizing the impact of the computer replacement on plant operations. Problems which could occur from removing the P-250 from service while at power were properly identified, evaluated, and resolved by the licensee.

6.3 Annual Fire Drill

On October 15, 1992, the inspector observed the 1992 annual fire drill. Nuclear Group Administrative Procedure 3.5, "Fire Protection," requires that a site fire drill be conducted with local fire department participation. The local volunteer fire departments consisted of companies from Midland, Hookstown, Shippingport, Raccoon, and Industry. The inspector observed a good turnout from these organizations and a high level of participation.

The inspector noted several deficiencies that were the result of overall drill coordination by the drill controllers. For example, the volunteer fire departments were all dispatched to the site by the Beaver County Emergency Management Agency before the fire drill began. The fire departments arrived on site before they were ever requested by the nuclear shift supervisor. This indicates that a more thorough pre-drill briefing of the offsite agencies may be warranted in the future. The inspector does recognize that this did not have a major effect on the drill, as the fire departments were held at the staging area until they were needed. Another drill coordination deficiency was the failure of chemistry department

personnel to participate in the drill. Chemistry department personnel, along with operations personnel, are designated as fire brigade members. Although the minimum number (five) of fire brigade personnel was available and did participate in the drill, provisions should have been made for the shift chemist to participate. The inspector acknowledges that the on-shift chemist during the drill had other duties to fulfill; however, the chemistry department manager was never contacted by the drill coordinators to provide an extra chemist for drill participation. Another drill coordination problem was evident when the offsite hazardous material (HAZMAT) response team was kept at the staging area. One of the drill objectives was to test the facility response to a hazardous material spill. Although this objective was satisfied by the licensee's onsite HAZMAT team, drill coordinators did not ensure that the licensee personnel had an opportunity to interact with the offsite HAZMAT team.

Another concern of the inspectors was that fire brigade members were not initially afforded the opportunity to voice their own comments and to provide feedback to the responsible fire protection engineers. The offsite post-drill critique did not include members of the licensee's fire brigade. Additionally, the fire brigade was unable to conduct their own debriefing due to technical specification overtime considerations. One of the fire brigade's responsibilities is to cooperate with the offsite volunteer fire departments in a coordinated fire fighting role. Fire brigade members did inform the inspector that they were unsure of their role in interacting with the offsite departments. Communication problems between the fire brigade and offsite fire departments were identified by drill controllers and were a drill deficiency. The fire brigade chief did subsequently document and submit his own comments for evaluation.

Overall, these examples indicate a general weakness in regard to drill preparation and coordination by the licensee. The inspector discussed these concerns with the licensee management and was informed that future fire drills will involve a greater degree of participation and coordination by emergency planning specialists. The inspector is satisfied with this action to enhance drill quality as the emergency planning specialists have greater expertise in the planning and conduct of drills. Additionally, the inspector was informed that operations management would have a greater degree of oversight in fire brigade training and drilling so that fire brigade members are afforded the opportunity to voice their own comments for evaluation.

7.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (40500, 71707, 90712, 91700)

7.1 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 follow-up. The following LER was reviewed:

Unit 1:

92-08 Incomplete Containment Hydrogen Analyzer Surveillance as a Result of Inadequate Change Implementation.

This event is discussed in NRC inspection report 92-20.

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

7.2 Unqualified Reactor Coolant Pump Undervoltage Relays

On October 2, 1992, the licensee concluded that the reactor coolant pump (RCP) bus undervoltage relays, which start the Unit 1 steam driven auxiliary feedwater (AFW) pump during a small break LOCA, could not be relied upon because they were not Class 1E. The relays were still capable of functioning. This was reported on October 21, 1992, by an Emergency Notification System (ENS) call. Further review by the licensee determined that Unit 2 has a similar design. The ENS call was updated to include Unit 2. The licensee is preparing an LER on this event.

Unit 1 was in cold shutdown when the unqualified RCP undervoltage relays were discovered. To correct the design deficiency at Unit 1, the licensee implemented a design change to provide an automatic start of the steam driven auxiliary feedwater pump upon receipt of a safety injection (SI) signal. Design change 1930 wired a Class 1E SI signal slave relay output (Train 'A' and 'B') into the start circuit for the AFW pump. The design change was completed prior to the plant exiting cold shutdown conditions. The start of the steam driven AFW pump is now consistent with the Westinghouse small break LOCA analysis. The licensee satisfactorily performed operational surveillance test 1.7.11, "CHS and SIS Operability Test," which tested the opening of steam supply valves (TV-1MS-105A and B) upon receipt of the SI signal.

A modification of the Unit 2 steam driven AFW start circuit similar to that performed on Unit 1 is planned for the next outage. The basis for continued operation (BCO) of Unit 2 until that modification is completed was prepared by the licensee. Essentially, the basis is that other start signals (primarily low-low steam generator level) are available that will start the steam driven AFW pump. The inspector discussed this BCO with the NRC project manager and Region I. The BCO provided an adequate basis for continued operation.

This AFW start signal issue was identified by the licensee while preparing a safety evaluation to support increased steam generator tube plugging. This shows that the licensee did a thorough review of accident analysis assumptions during the preparation of that assessment.

The same non 1E RCP bus undervoltage relays that provide this AFW start signal also provide the input to the RCP bus undervoltage reactor trip signal. The licensee had reviewed the use of these relays for this reactor protection system function in 1991 in response to Information Notice 91-11. The licensee concluded that both the RCP bus undervoltage and underfrequency relays should have been designed for Class 1E application. However, the purpose of these trips is to protect the core from loss of forced flow and three additional protection functions provide adequate diversity in protection for the complete loss of RCS flow transient. These diverse trips are loss of RCS loop flow, RCS loop overtemperature, and RCP breaker open. These three diverse trips are from 1E relays. The issue of using non-1E relays was previously reviewed in NRC inspections 334/81-28, 82-06, and 82-08 and found acceptable. The inspector discussed this issue with the NRC project manager and Region I and confirmed that adequate loss of flow protection is provided by these diverse trip signals.

8.0 EXIT MEETING AND NRC STAFF ACTIVITIES

8.1 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 November 25, 1992, with Beaver Valley management summarizing inspection activity and findings for this period.

8.2 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
10/23/92	Confirmatory Chemical and Radchem Measurements	92-23/23	J. Kottan
10/30/92	Procedurally Induced LOOPs	92-25/25	J. Beall

8.3 NRC Staff Activities

Inspections were conducted on both normal and backshift hours: 17 hours of direct inspection were conducted on backshift; 16 hours were conducted on deep backshift. The times of backshift hours were adjusted weekly to assure randomness.

R. Janati, Nuclear Engineer, Pennsylvania Department of Environmental Resources (DER) visited the site and inspectors on October 20, October 22, and November 16 and discussed inspection activities and the licensee's performance.