U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-334/86-06

Docket No. 50-334

Licensee: Duquesne Light Company
One Oxford Center
301 Grant Street
Pittsburgh, PA 15279

Facility Name: Beaver Valley Power Station, Unit 1

Location: Shippingport, Pennsylvania

Dates: March 11 - April 18, 1986

Inspector: W. M. Troskoski, Senior Resident Inspector
A. A. Asars, Resident Inspector

Approved by: L. E. Tripp 5/1/86
L. E. Tripp, Chief, Reactor Projects Section 3A date

Inspection Summary: Inspection No. 50-334/86-06 on March 11 - April 18, 1986.

Areas Inspected: Routine inspections by the resident inspectors (132 hours) of licensee actions on previous inspection findings, plant operations, housekeeping, fire protection, radiological controls, physical security, engineered safety features verification, maintenance activities relating to the river water system, surveillance testing, EDG fuel oil system, and followup on special reports.

Results: Two violations were identified: failure to qualitatively assess RHR heat exchanger outlet temperature remote shutdown monitoring instrumentation channel TRB-RH-606 as inoperable (Detail 4.b.1), and failure to demonstrate individual smoke detector alarm operability during surveillance testing (Detail 8). One deviation was identified: fuel oil day tank support stands with incomplete and poor quality welds and lack of QC inspection records. Problems continued to be experienced with feedwater control valve reliability (Detail 4.b.2).

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DETAILS

1. Persons Contacted

During the report period, interviews and discussions were conducted with members of licensee management and staff as necessary to support inspection activity.

2. Plant Status

The plant operated at full power throughout the inspection period with the exception of a reduction to about 30% power on April 9 - 12, 1986, for repair of the B main feedwater control valve (detail 4.b.2).

3. Followup On Outstanding Items

The NRC Outstanding Items (OI) List was reviewed with cognizant licensee personnel. Items selected by the inspector were subsequently reviewed through discussions with licensee personnel, documentation reviews and field inspection to determine whether licensee actions specified in the OIs had been satisfactorily completed. The overall status of previously identified inspection findings was reviewed, and planned and completed licensee actions were discussed for those items reported below:

(Closed) Unresolved Item (83-25-01): Review of licensee procedures for updating control room valve operating number diagrams (VONDs). This item originated as a result of an incomplete VOND which was consulted during preparation of an equipment clearance for maintenance of a hotwell sample pump. A newly installed equalizing line to the condenser vacuum instrumentation header was left off the VOND and subsequently the equipment clearance; this resulted in control room indication of an apparent loss of condenser vacuum. Station Administrative Procedure (SAP) 25, Organizational Responsibilities for Control of Revisions and Reissue of VONDs, was issued in November of 1984. It delineates each groups' responsibilities in assuring that VONDs, particularly those in the control room, are updated as soon as practical after the design change package (DCP) has been turned over, regardless of QA category. Through discussions with licensee personnel, the inspector determined that those responsible for update of VONDs are aware of their duties. The equalizing line has since been disconnected, and the inspector verified that the control room VONDs accurately represent this plant configuration. Also, the inspector reviewed DCP 562, Installation of Dedicated Auxiliary Feedwater Pump, modifications and verified that this additional system, which was installed during Winter, 1984, is represented on the control room VONDs. The inspector had no further concerns and this item is closed.

(Closed) Unresolved Item (83-25-02): Implementation of administrative controls to ensure that the technical specification/procedure matrix is updated as necessary. This item was previously discussed in NRC Inspection Report 50-334/85-02, detail 2. SAP 29, Technical Specification or Matrix Changes, was implemented on March 22, 1985. Section VI.D, Request for Matrix Change,

delineates the responsibilities of the group initiating the change and the nuclear safety group reviewing and either accepting or rejecting the proposed matrix change. The inspector had no further concerns and this item is closed.

(Closed) Unresolved Item (84-20-01): Followup on corrective actions to prevent gaseous waste discharges without chemistry sampling for tritium (H3). In September of 1984, a gaseous decay tank was released without sampling for H3 due to miscommunication between operators and the shift chemist. Sampling for H3 can only be done while the discharge is in progress due to system design. To ensure that the shift chemist is informed of the discharge and prepared to perform the H3 sample, Radcon Manual Form 6.2, Radwaste Discharge Authorization, requires that the shift chemist sign and date the form immediately prior to the discharge. Through discussions with operations and chemistry personnel and review of the H3 sample results from several recent discharges, the inspector determined that these personnel are knowledgeable of requirements and procedures for gaseous release. There have been no recurrences, this item is closed.

(Closed) IFI (85-12-06): Review of station equipment clearance procedures for establishing isolation points. This item was discussed in NRC Inspection Report 50-334/85-12, detail 7. It concerns inadequate equipment clearance procedures which failed to establish isolation points and made it possible for construction personnel to inadvertently initiate a pressure drop in the station air system. The inspector reviewed and walked down the equipment clearance permit for Design Change Package (DCP) 221. The purpose of this DCP is to install permanent piping to connect the RWST to the fuel pool purification system to allow cleaning of the RWST water during normal plant operation. A 2 inch line is being installed between the discharge of the refueling water recirculation pumps and the pool purification pump's suction. The inspector verified that isolation points were established and that each valve was closed and red-danger-tagged. Discussions with operations personnel indicated that they are knowledgeable in the clearance procedure requirements described in OM Chapter 48, Conduct of Operations, Section 6 - Clearance Procedures. The inspector had no further concerns; this item is closed.

(Closed) IFI (85-14-01): Develop a station administrative procedure to state how the overall station surveillance program is to be administered. SAP 33, Control and Coordination of Surveillance Tests and Calibration, was issued on March 24, 1986. This procedure addressed the responsibility of every group interfacing with a TS surveillance test.

(Closed) IFI (86-01-01): Identify and eliminate cause of gas buildup in charging pump suction line. The inspector was informed by the licensee on March 21, 1986, that an independent audit of chemistry procedures conducted by an outside group (NUS) identified an error in the analytical analysis of the RCS hydrogen content. Specifically, the licensee's methodology failed to modify their analysis to account for standard temperature and pressure conditions. This error resulted in underestimating the RCS hydrogen content by 50%. Inspector review of the Westinghouse primary chemistry manual indicated that the recommended RCS hydrogen concentration range was between 20 and 50 cc/kg. The lower limit is imposed for oxygen scavenging reasons. The

chemistry supervisor contacted Westinghouse and determined that the 50 cc/kg upper limit was imposed to prevent gas accumulation in low pressure areas of the CVCS.

The inspector was informed that appropriate chemistry manual changes were made. No further gas buildup problems were experienced and this item is closed.

(Closed) IFI (86-01-03): Replace deformed river water system expansion joint and determine the cause of deformation. This item was previously discussed in NRC Inspection Reports 50-334/86-01 and 86-04. The emergency patch was installed during the week of March 17, 1986, per EM 61699 and CMP1-30WR-REJ-26-1M, Temporary Repair of REJ-26. The inspectors observed portions of the installation. The expansion joint vendor, Goodall Rubber Company, indicated that the expansion joint was rated for up to 26" Hg vacuum with an expected service life of 10 to 12 years. BVPS-1 was started up in 1976 and this particular joint has never been replaced. A metal expansion joint qualified for pressures from full vacuum to 85 psig will be installed in the upcoming refueling outage. An inspection of all accessible expansion joints was conducted by the licensee with no other irregular joints identified. Since the service life for these rubber expansion joints is approximately 10 to 12 years and the joints are approaching that interval now, evaluation of preventative maintenance practices to replace components before their expected end of life is Unresolved Item (86-06-01).

(Closed) IFI (86-04-05): Determine the cause of B charging pump lube oil heat exchanger (HX) failure. After removal of the damaged HX, the licensee found extensive corrosion on the inlet side as evidenced by "paper-thin" tubes. The licensee replaced the failed HX with an identical one and returned the charging pump to service. Through discussions with licensee personnel, the inspector determined that B and C charging pump HXs have copper tubes, while the A pump HX has a stainless steel tube bundle that was installed during the last refueling outage. Replacement of the B and C HXs with stainless steel tubed HXs is incorporated into DCP 311, Charging Pump Modifications, scheduled for the refueling outage to begin next month. The inspector had no further concerns. This item is closed.

4. Plant Operations

a. General

Inspection tours of the plant areas listed below were conducted during both day and night shifts with respect to Technical Specification (TS) compliance, housekeeping and cleanliness, fire protection, radiation control, physical security and plant protection, and operational and maintenance administrative controls.

-- Control Room
-- Primary Auxiliary Building
-- Turbine Building
-- Service Building

-- Main Intake Structure
-- Main Steam Valve Room
-- Purge Duct Room
-- East/West Cable Vaults
-- Emergency Diesel Generator Rooms
-- Containment Building
-- Penetration Areas
-- Safeguards Areas
-- Various Switchgear Rooms/Cable Spreading Room
-- Protected Areas

Acceptance criteria for the above areas included the following:

-- BVPS FSAR
-- Technical Specifications (TS)
-- BVPS Operating Manual (OM), Chapter 48, Conduct of Operations
-- OM 1.48.5, Section D, Jumpers and Lifted Leads
-- OM 1.48.6, Clearance Procedures
-- OM 1.48.8, Records
-- OM 1.48.9, Rules of Practice
-- OM Chapter 55A, Periodic Checks, Operating Surveillance Tests
-- BVPS Maintenance Manual (MM), Chapter 1, Conduct of Maintenance
-- BVPS Radcon Manual (RCM)
-- 10CFR50.54(k), Control Room Manning Requirements
-- BVPS Site/Station Administrative Procedures (SAP)
-- BVPS Physical Security Plan (PSP)
-- Inspector Judgement

b. Operations

The inspector toured the Control Room regularly to verify compliance with NRC requirements and facility technical specifications (TS). Direct observations of instrumentation, recorder traces and control panels were made for items important to safety. Included in the reviews were the rod position indicators, nuclear instrumentation systems, radiation monitors, containment pressure and temperature parameters, onsite/offsite emergency power sources, availability of reactor protection systems and proper alignment of engineered safety feature systems. Where an abnormal condition existed (such as out-of-service equipment), adherence to appropriate TS action statements was independently verified. Also, various operation logs and records, including completed surveillance tests, equipment clearance permits in progress, status board maintenance and temporary operating procedures were reviewed on a sampling basis for compliance with technical specifications and those administrative controls listed in paragraph 4a.

During the course of the inspection, discussions were conducted with operators concerning reasons for selected annunciators and knowledge of recent changes to procedures, facility configuration and plant conditions. The inspector verified adherence to approved procedures for ongoing ac-

tivities observed. Shift turnovers were witnessed and staffing requirements confirmed. Except where noted below, inspector comments or questions resulting from these daily reviews were acceptably resolved by licensee personnel.

(1) On March 19, 1986, the licensee informed the inspector that the remote shutdown panel (SDP) RHR heat exchanger outlet temperature indicator (TRB-RH-606) was determined to have been inoperable since December 25, 1985. This condition was discovered when I&C technicians began initial troubleshooting of this instrument channel under Maintenance Work Request (MWR) 852630, which was backlogged since December, 1985.

TRB-RH-606 has one channel with a recorder readout in the control room, a remote meter at the SDP, and input to the control room computer. Technical Specification 3.3.3.5, Remote Shutdown Instrumentation, requires TRB-RH-606 to be operable in Modes 1 - 3, or to restore it to operable status within 30 days, or to be in hot shutdown within the next 12 hours. TS Surveillance 4.3.3.5 requires operability to be demonstrated once per 30 days by performance of a channel check; which, per TS 1.10 is defined as a comparison of the channel indication and/or status with other indications desired from independent instrument channels measuring the same parameter.

OST 1.45.2, Remote Shutdown Panel Instrumentation Channel Check, compares the TRB-RH-606 SDP meter indication with control room recorder reading to verify agreement within 20° F. This channel has an onscale range of 50 - 400° F, with a normal ambient temperature of 70 - 80° F. When OST 1.45.2 was run on December 25, 1985, it was noted that both readings were downscale low (less than 50° F). Consequently, MWR 852630 was issued and the control room recorder was tagged out-of-service.

A priority code 5 was assigned to the MWR, signifying that the work should be completed within 30 days as failure to do so could result in loss of system operation. Because of this prioritization and the relative backlog of instrumentation MWRs, actual work did not begin until March 19, 1986. In the interim, two channel checks performed by OST 1.45.2 identified TRB-RH-606 as being inoperable with an MWR outstanding. The OSTs were reviewed by Shift Supervisors and accepted as complete without further investigation into the status of the channel or pending work under the MWR. Because the RHR system is not placed into service until the reactor coolant system temperature and pressure are less than 350° F and 450 psig, respectively, and the plant was always in Modes 1 thru 3 during this time frame, control room personnel failed to recognize the need to return it to operable status as soon as practical.

The inspector observed immediate corrective action which included changeout of a low level amplifier and loop calibration which identified a RTD cable shield ground condition inside containment. This

ground effectively interfered with remote indication readouts. However, a meter supplied with its own internal DC power was able to get an accurate indication from the process instrumentation rack. Upon further investigation, I&C Engineers determined that several lifted leads could remove the earth ground from the low level amplifier and provide continuity from the RTD cable shield to the module output. This restored the amplifier to its original isolated ground condition. Loop operation was consequently restored to normal. The inspector noted that an appropriate safety evaluation and log entries were made for the lifted leads. Permanent corrective action to troubleshoot the ground inside containment is scheduled for the fifth refueling outage.

Discussions with licensee personnel indicated that several long-term corrective actions are currently being contemplated. The first one concerns the quality of the instrumentation channel checks currently being performed. The TS definition 1.10, Channel Check, indicates that this shall be a qualitative assessment of channel behavior during operation by observation where possible, of channel indication and/or status as compared with other indications derived from independent instrument channels measuring the same parameters. This is a particularly weak review for any single channel source such as TRB-RH-606. Consequently, a review of all instrument channels referenced in the technical specification and the methodology and acceptance criteria applied to each channel check was reviewed by the licensee.

The second program weakness that this event identified was that the licensee's current MWR tracking system does not differentiate between a technical specification component time limit and a non-technical specification item. This differentiation is essential to ensure that technical specification items receive priority attention when compared to non-safety items as MWR backlogs develop.

The technical significance of the inoperable RHR heat exchanger outlet temperature indicator is relatively minor because there are other wide range temperature indications (0 - 700° F) for each hot and cold leg of the RCS at the SDP, that provide a good measure of the effectiveness of the core decay heat removal capability. Though this item was identified by the licensee during troubleshooting activities, it is not considered a licensee identified violation because three previously completed OSTs should have resulted in prompt identification and repair of the failed channel. The failure to demonstrate the operability of each remote shutdown monitoring instrumentation channel by performance of a monthly channel check to qualitatively assess channel behavior, is a Violation (86-06-02) of Technical Specification 4.3.3.5.

(2) On April 9, 1986, a weekly visual inspection of the feedwater control valves found two out of the four guide studs on the B control valve (FCV-FW-488) actuator broken. Reactor power was immediately reduced from 100% to about 50%, and allowed to drift down to 35% as Xenon built up over the next shift. When it reached 35%, the bypass feedwater control valve was put into service and FCV-FW-488 was isolated for repairs.

Upon disassembly of the valve, mechanics found that a nut was missing from the anti-rotation device on the valve plug. This is a similar problem to that discussed in Inspection Report 334/85-24 (details 3.b.2 and 3). Through discussions with maintenance engineers, the inspector determined that a modification that included use of a thicker star lock washer and tack weld, had not been performed on the B control valve as it showed no mechanical problem during the November, 1985 inspection. This modification was completed on April 10, 1986.

In response to the missing anti-rotation material reported in Inspection Report 334/85-24, the licensee obtained a safety evaluation from Westinghouse, the NSSS vendor, stating that continued operation was acceptable, but that the loose parts should be retrieved during the next refueling outage. Because the above modification was only performed on two of the three steam generator feedwater control valves, and the third valve subsequently failed, all three steam generator secondary sides will now have to be opened up to inspect for the loose parts. This demonstrates a weakness in regard to ensuring sound corrective action for secondary side mechanical problems. Unresolved Item (85-24-01) is tracking feedwater control valve reliability problems.

The broken actuator guide stud phenomena had previously occurred in June, 1984, on the actuator for the C feedwater control valve. Through discussions with Maintenance Engineers, the inspector determined that parts from several actuators had been interchanged without recording where each was used. Therefore, the B actuator could have been the one on the C valve that failed. Further review of this area is being tracked as Unresolved Item (85-24-02).

During the power reduction, the delta flux became positive and exceeded the axial flux difference limit specified in TS 3.2.1 for 490 minutes. With the core at end of life conditions, it was not possible to return the delta flux to within the target band limits until after the xenon transient caused by the 65% power reduction peaked. The inspector verified that thermal power was maintained under 50% for 24 hours plus the accumulated penalty minutes. Full power was subsequently achieved on April 12, 1986, without further problems.

(3) During the first part of April, 1986, multiple low RCS loop 1 channel 2 flow alarms were received in the control room. This specific instrument channel had been causing similar problems during October, 1985. At that time, several parts were replaced in the transmitter (F-415) and a spurious trip occurred on October 25, 1985, while valving it in (see IR: 334/85-22, detail 3.b.3) due to a defective calibration procedure (MSP 6.29). This time, I&C opted to replace the faulty transmitter with a spare.

In preparation for the transmitter replacement, a spare was to be bench tested on April 10, 1986. The inspector observed setup of the test instrumentation, and noted that a copy of MSP 6.42, Reactor Flow Transmitter Response Test, marked "For Information Only" was being reviewed by the technicians. The inspector asked when an approved copy would be obtained for use and was informed that the I&C engineer had instructed them to use this one for guidance. Further discussions determined that the licensee was in the process of developing a generic time response bench test for replacement transmitters. Since the RCS flow time response is required by Technical Specification 4.3.1.1.3, the inspector noted that use of an approved procedure would be required. The MSP was subsequently updated and approved for use. As the generic procedure was in the process of being developed, the inspector had no further concerns. After the transmitter was installed and calibrated, no further alarm spikes occurred from this instrument channel.

The RPS response time test methodology and data were reviewed by the inspector. The 18 month cycle test (TS 4.3.1.1.3) is performed for DLC by Westinghouse, using noise analysis techniques. Individual transmitters installed as replacements by the licensee are tested by generation of a ramp signal, and this time is added to the instrument channel, reactor trip breaker and gripper coil release times for each RPS channel. This information is formally documented in BVT 1.13-1.1.8, Reactor Trip Time Responses. Both test methods are referenced in draft standard ISA-dS67.06. No concerns were identified.

c. Plant Security/Physical Protection

Implementation of the Physical Security Plan was observed in the areas listed in paragraph 4a above with regard to the following:

-- Protected area barriers were not degraded;

-- Isolation zones were clear;

-- Persons and packages were checked prior to allowing entry into the Protected Area;

-- Vehicles were properly searched and vehicle access to the Protected Area was in accordance with approved procedures;

-- Security access controls to Vital Areas were being maintained and that persons in Vital Areas were properly 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 lighting was maintained.

No discrepancies were observed.

d. Radiation Controls

Radiation controls, including posting of radiation areas, the conditions of step-off pads, disposal of protective clothing, completion of Radiation Work Permits, compliance with the conditions of the Radiation Work Permits, personnel monitoring devices being worn, cleanliness of work areas, radiation control job coverage, area monitor operability (portable and permanent), area monitor calibration and personnel frisking procedures were observed on a sampling basis.

No deficiencies were observed.

e. Plant Housekeeping and Fire Protection

Plant housekeeping conditions including general cleanliness conditions and control of material to prevent fire hazards were observed in areas listed in paragraph 4a. Maintenance of fire barriers, fire barrier penetrations, and verification of posted fire watches in these areas were also observed. The inspector identified no concerns.

5. Engineered Safety Features (ESF) Verification

The operability of the River Water System was verified during the week of March 17, 1986, by performing walkdowns of accessible portions that included the following as appropriate:

a. System lineup procedures matched plant drawings and the as-built configuration.

b. Equipment conditions were observed for items which might degrade performance. Hangers and supports were operable.

c. The interior of breakers, and electrical and instrumentation cabinets were inspected for debris, loose material, jumpers, etc.

d. Instrumentation was properly valved in and functioning, and had current calibration dates.

e. Valves were verified to be in the proper position with power available. Valve locking mechanisms were checked, where required.

No deficiencies were identified.

6. Maintenance Activities

The inspectors observed portions of selected maintenance activities on safety-related systems and components to verify that those activities were being conducted in accordance with approved procedures, technical specifications and appropriate industrial codes and standards. The inspectors conducted record reviews and direct observations to determine that:

-- Those activities did not violate a limiting condition for operation.

-- Redundant components were operable.

-- Required administrative approvals and tagouts had been obtained prior to initiating work.

-- Approved procedures were used or the activity was within the "skills of the trade."

-- The work was performed by qualified personnel.

-- The procedures used were adequate to control the activity.

-- Replacement parts and materials were properly certified.

-- Radiological controls were properly implemented when necessary.

-- Ignition/fire prevention controls were appropriate for the activity.

-- QC hold points were established where required and observed.

-- Equipment was properly tested before being returned to service.

-- An independent verification was conducted to verify that the equipment was properly returned to service.

The following activities were reviewed:

a. The licensee removed both auxiliary river water pumps (WR-P-9A and B) from service on March 26, 1986, to inspect the intake basin. Divers reported the accumulation of a large amount of silt (about 18 feet) in the basin and surrounding areas. Technical Specification 3.7.13.1 requires at least one auxiliary river water subsystem to be operable or the plant

must be placed in Hot Standby within seven days. The Operations Director informed the inspector that it would take more than seven days to completely clear the bays. Therefore, it was the station's intention to do it in steps to maintain the technical specification time limit.

b. The No. 1 Emergency Diesel Generator (EDG) was taken out of service on March 26, 1986, for performance of preventative maintenance on the air start system. The inspector observed portions of this maintenance and verified that the No. 2 EDG surveillance tests were conducted per Technical Specification 3.8.1.1. This preventative maintenance is part of the EDG vendor, Morris Knudson, recommended program to improve EDG reliability. At this time, the licensee was replacing the EDG air start motors after six months of service for examination. In September of 1985, these motors were removed, replaced and sent to the motor vendor, Ingersol Rand, for refurbishment - rust had formed in the motor due to moisture in the air system. Of the four air start motors installed during this maintenance, three were newly refurbished and one was from warehouse stock. During post maintenance testing, the EDG failed to start from the control room when the No. 2 air start set was selected; this set contained one refurbished motor and the unrefurbished stock motor. With the No. 1 air start set selected, the EDG started as required. The preferred start selector switch was placed in the No. 1 air start set position and red danger tagged in order for the No. 1 EDG to be placed back in service. The motor which failed was sent for refurbishment along with the motors removed during this maintenance. On March 27, the failed motor was replaced with a spare refurbished one. Post maintenance testing was satisfactory and the No. 1 EDG was returned to service.

Vendor analysis of the removed (refurbished) motors concluded that no water, rust or vane deterioration was present. Investigation into the cause of the motor failure in the No. 2 air start set during testing revealed that the motor was assembled for a left-hand rotation instead of the correct right-hand rotation. The vendor will provide a report to the licensee describing further details. It was impossible for licensee receipt inspection of these motors to detect the misassembled motor. Post maintenance testing adequately identified the motor as defective.

The air start system motors for the No. 2 EDG had been changed out and replaced in September of 1985 along with those for the No. 1 EDG. Current plans are to inspect these motors during the upcoming refueling outage. The licensee is also considering incorporating an air dryer into the air start system to prevent any further motor degradation. Maintenance of the EDG air start system as a portion of the EDG reliability program is being tracked as IFI (85-18-06).

c. The 2B air start system compressor for the No. 2 EDG (EE-C-2B) was removed from service on March 31, 1986, because of excessive check valve leakage which resulted in a very slow bleed down of the No. 2 EDG air start tanks. Compressor 2B was isolated and the cross connect to com-

pressor 1B (EE-C-1B) was opened and yellow caution tagged to allow for pressurization of the air start tanks as necessary. The check valve, manufactured by Lunkenheimer, was replaced with an available spare. Later that same day, the relief valve to compressor 1B (RV-EE-203) was discovered to be lifting frequently. Compressor 2B was returned to service and compressor 1B was removed from service for repairs. The licensee replaced the relief valve but during post maintenance testing found that the valve continued lifting frequently. Initially, the licensee believed the root cause to be a defective pressure switch on the compressor failing to shut it down when the desired pressure was reached. Further investigation indicated that the relief valve was lifting below its setpoint of 220 psig. This valve is a one-half inch Knuckle relief valve with a set lifting pressure of 220 psig. This particular relief valve is used only in the EDG air start system on the air start tanks and the compressors. The licensee tested other identical valves which were in stock and found them to also lift well below their setpoint. Currently, the licensee is planning to replace all of these relief valves and the check valves with similar models during the upcoming refueling outage.

d. On April 2, 1986, the 1C River Water Pump discharge valve MOV-RW-102C1, failed to open during performance of OST 1.30.6, Reactor Plant River Water Pump 1C Test. This particular valve has failed twice before this year (see NRC Inspection Report 334/86-04, detail 6.a) due to mis-set limits and linestarter coil hang up. Investigation revealed a failed torque switch. The licensee placed 1C River Water Pump in pull-to-lock and yellow caution tagged both the pump and its discharge valve until the torque switch could be replaced. As of the close of this report period, the valve has not been repaired due to torque switch unavailability. The inspector discussed with licensee personnel the necessity of maintaining spare parts such as torque switches which are generic to many plant motor operated valves.

7. <u>EDG Fuel Oil System</u>

A walkdown of the emergency diesel generator (EDG) fuel oil system by the inspector on March 26, 1986, identified a potential safety concern relating to the fabrication and construction of the fuel oil day tanks (EG-TK-2A and B). These tanks are located in each EDG room and are mounted above floor level to allow for gravity drain of the fuel when the EDGs are running. Table B.1-1, Structures and Systems Requiring Design for Seismic Loading, of the Beaver Valley Power Station Unit 1 FSAR specifies that these tanks be designed as Seismic Category 1 components. Because a number of the welds on each tank support craddle appeared to be of such poor workmanship that their quality could be seriously questioned, the inspector requested that the licensee verify that this safety related component would maintain its integrity through a design based earthquake as specified in the FSAR.

OQC performed an inspection of the support welds on the fuel oil day tanks and issued Quality Control Report 259 on April 4, 1986. The results of this inspection revealed that many of the welds are seriously questionable. At that time, no definitive determination was made on any of the welds because the licensee was unable to determine either the weld code or acceptance criteria applied to these components.

The inspector reviewed several purchase orders related to the original procurement of these components. Each was purchased to Seismic Category I requirements. However, no installation instructions or supporting QC inspection reports could be found to substantiate that these tanks were fabricated to any welding code. FSAR Section B.2.2.4, Specification Requirements - Seismic Design Control, states that equipment specifications are prepared to ensure that they are in full compliance with the FSAR assumptions, and that all necessary seismic information for the design and verification of components and equipment are provided to vendors of seismic Class I components. All vendor supplied documentation is then reviewed by the architect-engineer to ensure component adequacy with respect to the current criteria. The vendor's method for documenting seismic adequacy is then to be reviewed in detail for approval prior to installation. The failure to ensure that the EDG fuel oil day tanks were constructed, installed and inspected to industry codes applicable to seismic structures, is a Deviation (86-06-03), from Section B.2.2 of the FSAR.

The General Manager of Nuclear Operations informed the inspector that this deficient condition would be corrected prior to plant startup from the Fifth Refueling Outage scheduled for May thru August, 1986. Through discussions with NRC Region I Management, this timetable for corrective action was determined to be satisfactory.

8. EDG Room Smoke Detection System

a. Background

On March 26, 1986, during performance of OST 1.36.2, Diesel Generator No. 2 Monthly Test, operations personnel noticed that the Light Emitting Diode (LED) on smoke detector D100 was lit due to smoke generated during a DG start with no corresponding control room fire alarm activation. Further investigation by licensee personnel revealed that two of the three smoke detectors (D100 and D101) in the No. 2 Diesel Generator (DG) Room were inoperable. The plant fire detection system is a Honeywell, Inc. system, installed and maintained by Honeywell personnel. The smoke detection system for No. 2 DG Room was declared inoperable and an hourly fire watch was posted per TS 3.3.3.6.

Honeywell personnel arrived on site on March 31, 1986, to troubleshoot the fire protection system. Technicians verified that D100 and D101 were inoperable because of missing and loose resistors in detector wells. The necessary repairs were made.

On April 3, 1986, licensee personnel informed the resident inspectors of the results of the investigation, and on April 4, 1986, Honeywell personnel returned to the site to perform a revised (clarified) OST 1.33.16, Smoke Detector Instrumentation Test, on the entire plant smoke detection system. The inspector observed the performance of the test in the reactor trip breaker and No. 2 DG room.

b. Smoke Detection System Description

The smoke detection system was initially installed per the original plant design in 1974 to meet the then existing fire protection codes. This system consisted of Honeywell TC100A smoke detectors, Pyrotronics W931 local control panel (manufactured by Pyrotronics for Honeywell), data gathering panel (DGP), main fire panel, control processing unit (CPU) and a data receiving panel (DRP) (See Attachment 1). Such systems are currently installed in the control room, cable spreading rooms, switchgear rooms, and diesel generator rooms.

The remaining smoke detection systems were installed at a later date to comply with 10 CFR 50, Appendix R, requirements and contain Honeywell W939 local panels. The TC100A detectors have been replaced on an as-needed basis with a comparable but updated model, TC100C. Both detectors are functionally identical. For the Pyrotronics W931 panel to function as designed, an additional 470 OHM resistor is necessary for each detector - it is installed in the detector well. This resistor ensures that the detector draws enough current to activate the W931 panel alarm and in turn, the control room alarm. Without it, the local panel and all subsequent panels will not alarm but the LED located on the individual detector will light. It is important to note that the additional resistor is necessary only in those systems containing the Pyrotronics W931 panel. Currently, there are 17 Pyrotronics W931 panels in use in the plant.

c. Troubleshooting

Troubleshooting of the system by Honeywell personnel on March 31, 1986, revealed a missing resistor in detector D100 and a loose connection for the resistor in detector D101. Licensee records indicate that Honeywell last replaced D100 on January 7, 1985 and D101 on August 29, 1984. Detector D100 had been identified as defective and replaced during performance of OST 1.33.16. Detector D101 was replaced during a trouble call for that detector. Immediately after replacement, the applicable portion of the OST was performed to ensure operability. Due to inadequate performance of the OST, Honeywell personnel failed to identify the missing resistor and the potentially loose resistor. Therefore, operability of the control room alarm function for at least one of these two detectors after replacement was never demonstrated.

d. Surveillance Testing

OST 1.33.16, Smoke Detection Instrumentation Test, was developed by DLC in conjunction with Honeywell to verify the operability of the fire detection equipment. Licensee procedures group personnel accompanied Honeywell technicians during performance of the OST and made changes as deemed necessary during procedure development and revision. The portion of the OST which is applicable to the TC100A detectors reads as follows:

-- attach detector testing instrument to detector

-- depress test button and verify local detector LED illumination and that an alarmed condition is indicated in the control room

-- depress reset button, verify LED extinguishes, reset control room indication

-- record the necessary data on the data sheet

-- perform these steps for each detector tested

e. Requirements

Technical Specification 4.3.3.6.1 requires that the fire detection instrumentation accessible during normal plant operation for each fire detection zone listed in Table 3.3-10 shall be demonstrated operable at least once per six months by performance of a channel functional test. A channel functional test, as defined by TS 1.11, is the injection of a simulated signal into the channel as close as practical to the sensor (detector) to verify operability including alarm and/or trip functions.

Implementation of OST 1.33.16, Smoke Detector Instrumentation Test, on the smoke detection system in the No. 2 Diesel Generator Room failed to demonstrate individual detector operability in that a complete channel functional test was not performed for each detector. It was verified that the LED on each detector would light but not that the control room alarm would annunciate. This is a Violation (86-06-04).

The remaining detector (D99) apparently remained operable throughout this time period. Thus, the alarm function was not lost; however, the fire (smoke) detection system for this zone was vulnerable to a possible single failure. The other fire detection system for this zone which uses heat detectors was operable during this period.

f. Qualification of Inspection and Testing Personnel

Station Administrative Procedure (SAP) Chapter 12, Qualification of Inspection and Testing Personnel was developed to ensure that personnel who perform inspection examinations and testing activities involving Category I equipment are qualified per ANSI N45.2.6, Qualification of

Nuclear Power Plant Inspection, Examination and Testing Personnel (1978). This SAP stipulates that contractor or consultant personnel who perform applicable activities shall be certified in accordance with their own QA program or with the SAP. They shall provide documentation of this compliance to the Station Superintendent.

Category I equipment, as defined by the licensee's QA Program, includes equipment which is vital to the safe shutdown of the station or to prevent or mitigate the consequences of a postulated accident. The fire protection system is classified by the QA Program as Category F. This category is defined as all structures, systems and components that fall within the Fire Protection System, in safety-related and non-safety-related areas. Primarily the Fire Protection System has been installed as Category III (non-essential for safety), however, due to its installation and interaction with safety and non-safety-related structures, systems and components, the fire protection system must be adequately reviewed and controlled. Surveillance of this system is a technical specification requirement.

Discussions with the Plant Manager indicated that vendor personnel performing surveillance testing did not receive indoctrination concerning procedure adherence. Furthermore, licensee control and overview of contractor performance of smoke detector surveillance testing was inadequate in that it failed to note the widespread procedural adherence problems. However, this appears to have been an isolated case involving inadequate contractor control. A licensee evaluation of 276 Beaver Valley Unit 1 incident reports covering most of 1984-85 identified only five incidents due to contractors. Only one of these incidents had any safety significance. The inspector had no further concerns in this area.

9. Followup on Special Reports

LER: 86-01 describes two events that occurred on February 10, 1986: (1) reactor trip due to vital bus No. 3 failure while at full power, and (2) inadvertent RPS actuation by intermediate range detector N-35 while in Mode 3. Both of these items were previously discussed in NRC Inspection Report 334/86-04, detail 4. Since then, the inspector has been informed that a station modification request was initiated to determine the feasibility of adding additional air conditioning capabilities in the switchgear room. Additionally, the licensee was considering a modification that would add static switches to ensure a fast transfer from the normal vital bus power supply to its auxiliary source within one cycle, ensuring no interruption of instrument power.

10. Exit Interview

Meetings were held with senior facility management periodically during the course of this inspection to discuss the inspection scope and findings. A summary of inspection findings was further discussed with the licensee at the conclusion of the report period.

ATTACHMENT 1