U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.: 50-334/88-22 License Nos.: DPR-66
50-412/88-16 NPF-73

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

Facility Name: Beaver Valley Power Station, Units 1 and 2

Location: Shippingport, Pennsylvania

Dates: June 1 - July 15, 1988

Inspectors: J. E. Beall, Senior Resident Inspector
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Approved by: Lowell E. Tripp AUG 12 1988
Lowell E. Tripp, Chief Date
Reactor Projects Section No. 3A
Division of Reactor Projects

Inspection Summary: Combined Inspection Report No. 50-334/88-22 and 50-412/88-16 for June 1 - July 15, 1988.

Areas Inspected: Routine inspections by the resident inspectors of licensee actions on previous inspection findings, plant operations, security and physical protection, radiological controls, plant housekeeping and fire protection, maintenance activities, surveillance testing, annual fire drill, defective 4 KV overcurrent relays, emergency diesel generator problems, cable separation, in-office review of licensee event reports and review of periodic and special reports.

Results: One violation was identified regarding inadequate cable separation (Section 10). A licensee identified violation involving the failure to verify emergency diesel generator operability in accordance with Technical Specification requirements is discussed in Section 4.2.5. Three unresolved items were opened regarding (1) the resolution of the overcooling event that occurred following the June 7 reactor trip which resulted in a subsequent safety injection (Section 4.2.1), (2) more action which may be necessary to prevent events which could result in a complete loss of the Unit 2 control room annunciator system (Section 4.2.6), and (3) recurrent problems that have been experienced on the emergency diesel generator air start systems (Section 9). Continued improvements were noted in plant housekeeping and licensee event report quality.

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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 activities.

2. Summary of Facility Activities

At the beginning of the inspection period, both Unit 1 and Unit 2 were operating at full power. A Unit 1 reactor trip and safety injection occurred on June 7 when a non-licensed operator inadvertently tripped an operating reactor coolant pump, causing a low reactor coolant flow condition (Section 4.2.1). Two additional Unit 1 reactor trips occurred on June 9 (Section 4.2.2) and June 11 (Section 4.2.3) during plant startup evolutions, and were due to feedwater system control problems which resulted in low-low steam generator water level reactor trips. Operator error contributed to the June 9 reactor trip. The plant was subsequently restarted and full power was reached on June 13, and continued until the end of the inspection period. On June 15, a rapid manual turbine/generator load reduction was initiated on Unit 2 in response to degraded condenser parameters. A secondary plant shutdown followed for turbine protection, while the reactor was maintained at a low power level. The turbine/generator unit was placed back on line that same day and full power operation resumed on June 16, and continued to the end of the period.

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 review 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/completed licensee actions were discussed for the items reported below:

3.1 (Closed) Unresolved Item (50/334/88-11-02): Open Cable Junction Boxes and Cable Tray Cover Deficiencies. This item involved the identification by the inspector of several deficiencies in the Unit 1 cable spreading room directly beneath the control room. Cable junction boxes were found open and numerous cable tray covers were found missing, damaged or improperly installed. The licensee acted promptly to correct the identified deficiencies including repair/fabrication and installation of additional tray covers. The inspector conducted a followup inspection and noted that the identified deficiencies had been corrected. This item is closed, however, additional deficiencies were identified in the cable spreading room during the inspector's walkdown as discussed in Section 10 and a violation has been opened.

3.2 (Closed) Unresolved Item (50-334/88-17-01): Inadequate Cable Separation. This item involved portable cables which were routed in such a way as to provide inadequate separation with existing safety related cable. The licensee corrected the identified deficiencies, conducted area and overall plant walkdowns, and corrected additional self-identified items. This item is closed, however, additional separation deficiencies were identified by the inspector as discussed in Section 10 and a violation has been opened.

4. Plant Operations

4.1 General

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

-- Control Room
-- Auxiliary Building
-- Switchgear Area
-- Access Control Points
-- Protected Area Fence Line
-- Turbine Building
-- Safeguard Areas
-- Service Building
-- Diesel Generator Buildings
-- Containment Penetration Areas
-- Yard Area
-- Intake Structure

The operability of selected Engineered Safety Features systems were verified by performing detailed walkdowns of the accessible portions of the systems. The inspectors confirmed that system components were in the required alignments, instrumentation was valved-in with appropriate calibration dates, as-built prints reflected the as-installed systems and the overall conditions observed were satisfactory. The systems inspected during this period include the Emergency Diesel Generator, Safety Injection and Auxiliary Feedwater systems. No concerns were identified.

4.2 Operations

During the course of the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration and plant conditions. During plant tours, logs and records were reviewed to determine if entries were properly made, and that equipment status/deficiencies were identified and communicated. These records included operating logs, turnover sheets, tag-out and jumper logs, process computer printouts, unit off-normal and draft incident reports. The inspector verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. Inspector comments or

questions resulting from these reviews were resolved by licensee personnel. In addition, inspections were conducted during backshifts and weekends on June 3, 6:00 pm - 11:00 pm; June 8, 6:00 pm - 8:30 pm; June 12, 10:00 am - 7:30 pm; June 28, 6:00 pm - 8:30 pm; June 30, 6:00 pm - 9:30 pm; July 1, 4:00 am - 7:00 am; July 7, 2:00 am - 7:00 am. The inspectors verified that plant operators were alert and displayed no signs of fatigue or inattention to duty.

4.2.1 Reactor Trip and Safety Injection

On June 7, a reactor trip and safety injection (SI) occurred at Unit 1 from full power during the performance of a balance of plant surveillance test. Operations personnel were in the process of testing a station air compressor, when the procedure instructed them to open the associated 480 V AC breaker. A non-licensed nuclear operator inadvertently opened the 4KV "C" reactor coolant pump (RCP) breaker (1C5) instead of the 480 V AC station air compressor breaker (2C5). The loss of the "C" RCP resulted in an automatic reactor coolant system (RCS) low flow reactor trip at 9:55 p.m. A low pressurizer pressure safety injection automatically actuated 29 seconds following the reactor trip. An Unusual Event was declared at 10:12 p.m. in accordance with the Emergency Preparedness Plan (due to ECCS actuation). The SI system injected borated water into the RCS for about 17 minutes before the SI was terminated. The Unusual Event was terminated at midnight following plant stabilization and verification of shutdown margin. The licensee notified the NRC of the event in accordance with 10 CFR 50.72 reporting requirements.

Several problems were encountered during the event, including (1) the reason for reaching the low pressurizer pressure SI setpoint following an analyzed reactor trip was not apparent, (2) no first-out reactor trip annunciator was received, however, reactor operators observed the trip of the "C" RCP, the opening of the reactor trip breakers, and the control rods falling into the core, and (3) both emergency diesel generators (EDGs) automatically started as designed, however, the EDG No. 1 left bank air start motor pinions continued to attempt to engage (See Section 9 for additional details on the EDG system). The licensee found a faulty timer relay in the first-out logic control circuitry for the "C" RCP. A new relay was ordered and will be installed at a future time. Computer printouts also log the tripping of an RCP breaker. The inspector will verify that the timer relay is replaced during a subsequent inspection.

The licensee performed a detailed review of the June 7 reactor trip to determine the exact cause of the SI actuation. A simulator run was performed, however, was inconclusive. The licensee subsequently identified two dominant factors that contributed to the rapid primary plant depressurization. First, a rapid RCS cooldown and depressurization resulted from an over-response of the steam dump system due to a stagnant resistance temperature detector (RTD) manifold temperature in the "C" loop after the associated RCP was tripped. There are five valves on the "C" RTD bypass manifold which had previously (since 1984) experienced disc/stem separation problems. Under reversed flow conditions, the valves act to stop flow, thus causing the stagnant conditions which provided a false high average temperature signal. Second, the main feedwater regulating valve (FRV) trim modification, performed during the recent sixth refueling outage, increased the post-trip feedwater flow through the FRVs resulting in a more rapid cooldown. The severity of this effect is greater following a reactor trip that occurs during low power operations, since there is very little feedwater heating and upon a reactor trip, the FRVs initially open fully. Although the licensee determined that the first item appears to be the most dominant contributor, they have determined that the absence of either item would have precluded an SI actuation. This was confirmed on a subsequent plant trip on June 11 (without loop flow reversal). Pressurizer pressure dropped to 1880 psig on the June 11 reactor trip which is still very close to the SI actuation pressure of 1845 psig. The normal post-trip for pressurizer pressure should be about 2050 psig. This indicates that feedwater overfeeding remains a significant and continuing concern warranting additional licensee attention.

The licensee plans to remove the RTD manifold during the next refueling outage and replace the existing RTD with in-loop temperature instrumentation, a modification which will eliminate the bypass manifold stagnation concern. One fix which was instituted for the overfeeding concern was a change in the closure time for the FRVs from a minimum of 7 seconds to 5 seconds. This change is expected to reduce feedwater flow into steam generators and therefore, has the potential for reducing the possibility of experiencing similar RCS overcooling events immediately following a reactor trip. A related short-term licensee action was to provide instructions to plant operators to verify that the

auxiliary feedwater system is operating properly and to trip the main feedwater pumps if RCS pressure reaches 1950 psig following a reactor trip. These actions are expected to avoid an excessive cooldown and provide an adequate margin to the SI signal setpoint. Further review and implementation of additional recommendations are currently under review by the licensee.

Final resolution of the overcooling concerns will be reviewed during a subsequent inspection (Unresolved Item 50-334/88-22-01).

4.2.2 Feedwater Isolation and Reactor Trip

On June 9, a Unit 1 automatic reactor trip occurred from about 16% power during a plant startup following the June 7 reactor trip (Section 4.2.1). Adjustments had been completed earlier on the bypass feedwater regulating valves (BFRVs) in order to minimize flow oscillations that were experienced previously. Shortly after the unit was synchronized onto the system grid, steam generator water level oscillations were experienced as noted on all three steam generator level recorders. The "A" and "B" steam generator level swings appeared to be stabilizing, while the "C" continued to oscillate. The "C" controller was placed in manual, however, the high level setpoint was reached on that steam generator despite operator efforts to prevent large level oscillations. The high steam generator level caused a turbine trip, feedwater isolation and an automatic trip of the operating main feedwater pump. Both motor driven auxiliary feedwater pumps automatically started as designed. After the "C" steam generator level was restored to normal, the main feedwater pump was restarted and the auxiliary feedwater system secured. However, the feedwater water isolation signal was not reset by the plant operators and therefore, the feedwater isolation valves remained closed, preventing feedwater from reaching the steam generators. Within several minutes, steam generator water levels drifted downward until a low-low level reactor trip signal was generated on the "A" steam generator. Emergency operating procedures were followed by plant operators and the unit was stabilized in Mode 3. The licensee notified the NRC of the event in accordance with 10 CFR 50.72 reporting requirements. The initiating cause of this event was the failure of the "C" BFRV to adequately control steam generator water level while operating in the automatic mode. Additional checks and tuning of the BFRVs were performed. No hardware problems were found, but additional

troubleshooting activities were being performed at the end of the inspection. The licensee attributed the failure to reset the feedwater isolation signal to be a knowledge and experience deficiency that will be addressed through the Operator Retraining Simulator Program. The inspector will review the results of the BFRV troubleshooting activities and the effectiveness of the licensee's proposed corrective actions during subsequent routine inspections.

4.2.3 Feedwater Isolations and Reactor Trip

On June 11, Unit 1 experienced two feedwater isolations (FWIs) and a subsequent reactor trip from 13% power during the recovery from the reactor trip on June 9. During the startup evolution, steam generator (SG) feedwater level control was transferred from the bypass feedwater regulating valves (BFRVs) to the main feedwater regulating valves (MFRVs) at 13% power. Level control is normally transferred to the MFRVs at between 20% - 25%, however, control was transferred earlier during this startup in an attempt to eliminate control problems similar to those previously experienced with the BFRVs (on June 9). Plant operators were planning to bring the main turbine on-line with the MFRVs in service; however, the SG automatic level control system began to experience instability problems in that feedwater flow and SG level oscillations were noted. Although the operators attempted to manually control SG level, the "C" SG level increased to its high setpoint, resulting in a FWI. The FWI signal automatically caused (1) feedwater flow to be isolated; (2) a trip of the operating ("A") main feedwater pump (MFWP) and (3) an auxiliary feedwater system actuation.

The "C" SG water level was returned to normal within several minutes, the FWI signal was reset, associated equipment restored to normal ("A" MFWP was restarted) and the plant startup continued. The turbine was then placed on-line. SG level oscillations occurred again and another FWI signal was generated when the "A" SG water level rached its high level setpoint. The automatic FWI actions occurred as designed, including an automatic turbine trip (the turbine was not on-line when the first FWI occurred).

SG water levels were again returned to normal within a few minutes. Plant operators reset the FWI signal and attempted to restore normal feedwater flow by starting the "B" MFWP. The "B" MFWP was selected so as to reduce the number of consecutive starts of the "A" MFWP over a short period of time (per procedure). Control room operators noted a lower than normal feedwater flow following the pump start. It was then identified that the "B" MFWP discharge valve had not fully opened when the pump was started. Control room operators immediately secured the "B" MFWP and started the "A". Normal feedwater flow was then observed, however, before the feedwater system was able to recover the decreasing SG water levels, the low-low level setpoint was reached on the "A" SG, resulting in an automatic reactor trip. Plant operators stabilized the plant in Mode 3 using Emergency Operating Procedures. All three events were reported to the NRC in accordance with the reporting requirements of 10 CFR 50.72.

The licensee's followup investigation identified that unstable SG level control occurred because 1) under low flow conditions, the MFRVs do not respond as quickly as the BFRVs, and 2) without the turbine on-line, no extraction steam was available for feedwater preheating (feeding the SGs with relatively cold water contributed to the level stability problems). The "B" MFWP discharge valve motor-operator was tested to determine whether an electrical failure had occurred, however, no problems were found. Licensee investigation into the reasons for the failure of the "B" discharge valve to open is continuing and will be reviewed during a subsequent inspection.

The licensee provided instructions to plant operators to address the above concerns, including requiring that future plant startups be performed using the BFRVs until the reactor reaches at least 20% power and to perform the turbine startup at lower power levels in order to make extraction steam available for feedwater preheating. The licensee also discovered that two condenser steam dump system valves were not operating properly during this event, resulting in pressure surges that may have contributed to the SG levels control problems. The affected valves have been failed closed pending repairs. The inspector will monitor the effectiveness of the licensee's corrective actions during subsequent inspections.

4.2.4 Main Condenser Problems

On June 15, at 2:55 pm, Unit 2 control room operators initiated a load reduction in response to degraded condenser vacuum and temperature conditions. The power decrease and subsequent feed and bleed evolutions that were initiated to correct the problems failed to improve condenser vacuum or hotwell temperature. Within two hours, minimum load was reached on the main turbine/generator (10 MWE). At 5:00 pm, the turbine was manually shut down, the main generator output breakers were opened and the turbine was manually shutdown. The hotwell temperature returned to normal within several minutes, however, condenser vacuum did not return to its normal expected value. At 6:38 pm, vacuum was better and increasing while air ejector flow was decreasing. The licensee speculated that earlier air injector performance may have been degraded. All parameters were subsequently returned to normal and a turbine startup commenced. Full power was reached on June 16.

The licensee's followup investigation into this event identified several factors which may have contributed to the event. The first is that the outside temperature was high (93 F), which accounted for the initially higher hotwell temperatures. Earlier on June 15, the steam generator blowdown demineralizer was placed on clearance for maintenance, and the relatively hot blowdown flow was directed to the condenser hotwell. At 4:25 pm, the air ejectors backfired, dumping a relatively large amount of air into the condenser (when condenser parameters were already degraded). Additionally, during the feed and bleed evolution, a 4 inch valve was used versus an available 12 inch hotwell fill valve, which would have been more effective in reducing the hotwell temperature.

At the time of the event, plant operators had instructions to initiate a power reduction when the condenser backpressure reaches a predetermined value. Hotwell temperature was not referenced in the instructions. Once saturation conditions were reached during this event, efforts to restore the paramenters to normal were ineffective. To reduce the possibility of similar occurrences, the licensee developed a Condenser Back-pressure versus Condenser Outlet Cooling Water Temperature curve, which was provided to plant operators. The curve provides points at which power

reduction should be initiated to prevent reaching saturation conditions in the main condenser. A similar curve was developed for Unit 1. The licensee also began trending condenser parameters to monitor condenser operation. Additional significant events relating to degraded condenser performance have not occurred subsequent to the development of the performance curves. The inspectors will monitor condenser performance and operator response to adverse conditions during routine inspections.

4.2.5 Failure to Verify Diesel Generator Operability

On July 7, the Unit 1 No. 1 Emergency Diesel Generator (EDG) was removed from service to inspect and clean the air lines in the EDG air start system at 11:56 a.m. (Section 9) following the air start system failure on the previous day. Technical Specification (TS) 3.8.1, Electrical Power Systems, requires that the remaining EDG (No. 2 in this case) be demonstrated to be operable and that the offsite to onsite power distribution system breaker alignment be verified. At 2:38 pm, oncoming shift personnel questioned if the above actions were performed. When onshift Control Room personnel realized that those actions were not performed, the No. 2 EDG was immediately manually started from the Control Room and the appropriate checks were successfully completed at 2:50 p.m.

The No. 2 EDG had last been demonstrated to be operable at 4:06 p.m. on July 6, when the No. 1 EDG was inoperable due to the failure of the air start system. That EDG was returned to service later that day, and then again removed from service at 11:56 a.m. on July 7. The operability checks were missed due to personnel error possibly as the result of a misunderstanding of the previous testing and period of inoperability. In addition to the immediate corrective actions of verifying the operability of the No. 2 EDG, a procedure change has been completed which now specifies that the required operability verification for the remaining EDG be completed when one EDG is taken out of service. Additionally, Station Administrative Procedure No. 41, Clearance Procedure, will be reviewed to determine whether additional changes or instructions are needed to the emergency safeguards equipment clearance checklist. The inspector will independently review this procedure to determine whether changes are necessary.

Since the failure to meet the above TS requirements was identified by the licensee and this situation meets the criteria to be considered a licensee identified violation, in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR 2, Appendix C, no Notice of Violation will be issued.

4.2.6 Loss of Control Room Annunciator System

On July 7, Unit 2 experienced a brief (8 minutes) loss of control room annunciators while operating at full power. Prior to the event, technicians were troubleshooting problems with one of the three inverters that supply power to the control room annunciator system. During the troubleshooting activities, the common supply breaker to all three inverters tripped open due to overcurrent, resulting in a loss of control room annunciator window indication, horns and pushbutton control. A partial loss of the CRT (computer) alarm inputs also occurred. The annunciator system was restored by reclosing the common inverter supply breaker and de-energizing the affected inverter. For the duration of the event, plant operators monitored plant status using the CRT displays, plant computer and available charts and indicators in the control room. No plant transients were experienced The site emergency plan was not implemented because no plant transients were experienced and the annunciator loss did not exceed 15 minutes. On January 28, 1988, Unit 2 experienced a two hour loss of control room annunciators due to a fire which led to the declaration of an Alert.

Licensee followup investigation and troubleshooting activities identified that the cause for the event was a random component failure of a power bridge silicon control rectifier (SCR). The licensee is currently investigating the feasibility of providing a separate supply breaker for each of the individual inverters, thereby preventing a loss of all control room annunciators upon a similar type of component failure. Such a change in configuration would also facilitate maintenance activities on the inverters. Pending licensee determination of a method to prevent recurrence of similar events, this is Unresolved Item No. 50-412/88-16-01.

4.2.7 Increased Main Turbine Vibration

During this inspection period, increased vibration levels on the No. 4 bearing of the Unit 1 main turbine were observed. The licensee requested an offsite contractor to review and analyze test data on the bearing. The contractor determined that, at the time of the review, the vibration from the bearing had doubled (from 2 mils to 4 mils), since the recent restart from the sixth refueling outage (March, 1988), and had been increasing at a rate of 0.7 mils per week. At the end of the inspection, the vibration was relatively constant at about 7 mils. The contractor reviewed the vibration data from the most recent plant startup and found that the turbine had experienced up to 15 mils overall vibration amplitude for a considerable time while passing through the critical turbine rotor speeds, and concluded that something in the No. 4 bearing structure had changed to account for the elevated vibration levels. The contractor recommended that a general bearing structural inspection be performed at the next convenient time. The licensee instituted increased monitoring and trending of the No. 4 bearing. The licensee determined that if a displacement of 8.5 mils sustained or a sustained increasing vibration rate of greater than 0.5 mils per day is reached, the unit should be removed from service and the bearing be inspected for looseness and/or damage. If the unit is to be taken off line for a bearing inspection, a 9 to 10 day mini-shutdown is expected, and the reactor is planned to be maintained in Mode 3 (Hot Standby). The inspector will continue to monitor the licensee's associated activities.

4.3 Plant Security/Physical Protection

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 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 illumination was maintained.

No deficiencies were identified.

4.4 Radiological Controls

Posting 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. No concerns were identified.

4.5 Plant Housekeeping and Fire Protection

Plant housekeeping conditions including general cleanliness conditions and control and storage of flammable material and other potential safety hazards were observed in various areas during plant tours. Maintenance of fire barriers, fire barrier penetrations, and verification of posted fire watches in these areas were also observed. The inspector conducted detailed walkdowns of the accessible areas of both Unit 1 and Unit 2. Continued improvements were noted for both units. Individual deficiencies were identified to the licensee for resolution.

5. Maintenance

The inspector 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;

-- where necessary, radiological and fire preventive controls were adequate and implemented;

-- QC hold points were established, where required, and observed;

-- equipment was properly tested and returned to service.

Maintenance activities reviewed included:

MWR 882686	Change out four Air Start Motors for No. 1 EDG
MWR 880776	Replace Air Start Solenoid
MWR 880906	Replace No. 1 EDG left bank solenoid valve
MWR 883103	Replace isolation valve for starting air tank EE-TK-4C

No significant concerns were identified.

6. Surveillance Testing

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 surveillance testing activities were reviewed:

MSP 6.10	F-426 Reactor Coolant Flow Loop 2 Protection Channel III Test.
MSP 6.33	F-426 Reactor Coolant Flow Loop 2 Protection Channel III Calibration.
MSP 13.05	L-100A Refueling Water Storage Tank Level Loop Channel III Test.
OST 1.30.6	Reactor Plant River Water Pump 1C Test.
OST 1.36.1	Unit 1 Emergency Diesel Generator No 2 Monthly Test.
OST 2.36.1	Unit 2 Emergency Diesel Generator No. 2-1 Monthly Test.

The inspector found that minor steps in the test instrument connection instructions for Maintenance Procedure (MSP) 6.33 were apparently missing. Other minor discrepancies were found with respect to incorrect references to different sections/steps. The technicians performing the MSP understood what was to be accomplished, however, less experienced technicians could possibly be misled. The technicians noted the apparent human-factor type deficiencies on the attached MSP critique form for further review. Additionally, the inspector discussed this concern with the appropriate licensee personnel, who acknowledged the inspector's comments. No other concerns were identified.

7. Annual Fire Drill

The licensee conducted an annual site fire drill on June 9 to test the response and coordination among the onsite fire brigade, site security personnel and the offsite fire departments. The drill scenario included a lightning strike of a Unit 2 station service transformer, causing the sprinkler system water and burning oil to flow onto the ground. Both plants were to be operating at 100% power. Additionally, the scenario included an injured person in the Unit 2 Auxiliary Building during the fire.

The inspector witnessed the drill and associated activities. The emergency classification of the event (Unusual Event) was made properly and in a timely manner. Operations support in the control room was observed to be good. The fire brigade, radiological control, security and offsite fire department members provided similarly good support for the drill. The inspector noted that the licensee maintains a very good working relationship with the offsite fire departments. This is a continuing licensee strength. The drill was terminated when all trucks flowed water and the drill objectives were completed.

A critique was held by the licensee immediately following the drill. A weakness was identified with respect to the response and first aid treatment provided to the injured person. Other minor deficiencies were identified by drill controllers. An evaluation report was issued on June 28, which documents the noted deficiencies, proposed resolutions, responsibilities and due dates. These items will be tracked by the licensee's internal tracking system. The inspector reviewed the licensee's evaluation report and determined that the licensee was sufficiently critical of the drill activities. The overall performance of personnel and equipment was satisfactory.

8. Defective 4 kV Relays

On June 30, the licensee notified the NRC of a deficiency with 4 kV overcurrent relays provided by Brown Boveri (Model ITE-51). A relay component provided by Motorola was found to be subject to failures due to impurities which can cause spurious overcurrent trips. The components involved are silicon control rectifiers (SCRs), manufactured by Motorola before 1982. Unit 2 has experienced five such failures (three on safety-related components). The licensee completed a justification for continued operation (JCO) on July 1. A 10 CFR, Part 21 Report was submitted to the NRC in accordance with the requirements of that section.

The SCR impurity allows leakage current to gradually increase until the component short circuits and automatically trips the relay. Motorola has previously identified the problem and has instituted two different "burn-in" tests, one which subjects the SCR to a test (heat) environment with an applied voltage, while the other subjects the SCR only to the test environment. Any relays installed that were purchased prior to 1982 did not have the "burn-in" tests performed. Therefore, at the licensee's request, the relay manufacturer provided them with a test procedure which could be used to detect suspect SCRs.

The licensee tested all 138 ITE-51 relays on 4 kV feeder breakers. 46 of them are used in safety-related applications. Of the 138 relays tested, 11 were found to have leakage currents greater than the test acceptance criteria. Seven defective relays were installed on safety-related equipment. All defective relays were replaced.

The licensee's JCO concluded that continued plant operation was justified because the affected relays were in a continuously energized state (DC power supplied) for a period in excess of two years. The vendor stated that such a service time is equivalent to the "burn-in" test and therefore, impurities would have been identified via relay failure. The JCO also documented that Operations personnel will specifically check for tripped or flagged relays each shift and that there is an annunciation in the control room sequence of events recorder.

The inspector conducted an independent review and found that, upon a relay actuation, a control room alarm and computer printout will be annunciated. The alarm allows for a prompt investigation into the cause of the actuations. Additionally, plant operators could remove a failed relay from service via a bypass function, if needed. The inspectors will monitor the effectiveness of the licensee's actions during routine inspections.

9. Emergency Diesel Generator Problems

Several problems have been experienced during this inspection period with the Unit 1 Emergency Diesel Generator (EDG) Air Start System. As documented in NRC Inspection Report No. 50-334/88-01, the licensee committed to inspect the air start system associated with one of the EDGs in June of this year. The results of the inspection and two recent equipment problems are outlined below.

9.1 Air Start System Failure Following EDG Automatic Start

On June 2, a Maintenance Work Request (MWR) No. 882686 was initiated, which was to change out all four (2 in each bank) EDG No. 1 air start motors (ASMs). They were to be sent to an offsite contractor for inspection and repair, as necessary. Before the MWR was worked, a reactor trip and safety injection (SI) occurred on June 7 (Section 4.2.1). The SI generated an automatic start of both EDGs as per design, however, during attempts to secure the No. 1 EDG, the two left bank ASM pinions continued to attempt to engage due to an apparent faulty air start solenoid. The EDG was declared inoperable, and all four ASMs (both banks) were replaced per MWR 882686. The condition of the left bank ASM pinions were sufficiently degraded to suggest that they may have not properly disengaged immediately following the No. 1 EDG automatic start. The licensee also replaced the left bank air start solenoid valve, as it was suspected to have contributed to the ASM problem. Following a successful post maintenance test after the replacement of all four ASMs and the left bank solenoid, the No. 1 EDG was returned to service on June 8.

9.2 Air Start System Failure During Surveillance Testing

On July 6, during a backshift inspection, the inspector witnessed the performance of Unit 1 Operations Surveillance Test 1.36.1, EDG No. 1 Monthly Test. The EDG was manually started from the control room, and within about 10 minutes, sparks were observed coming from the ASM location. Plant operators immediately locally shutdown the EDG.

The subsequent inspection identified that the left bank ASM pinions had not disengaged. The left bank was then removed from service by isolating the associated air bottles and air compressor, and the No. 1 EDG was declared inoperable. During the time that EDG No. 1 was out of service, EDG No. 2 was demonstrated to be operable and the offsite to onsite power distribution system breaker alignment was verified in accordance with the requirements of Technical Specification (TS) 3.8.1, Electrical Power Systems. The licensee removed and inspected the left bank solenoid valve and air start motors. Rust fragments were found on the solenoid valve seat. The inspection of the ASM identified that one pinion was severely damaged, while the other one showed abnormal wear. The left bank solenoid and both ASMs were subsequently replaced with qualified spares. The damaged ASMs were sent to an offsite contractor for inspection and repairs. The No. 1 EDG was subsequently tested satisfactorily and returned to service later that day.

On July 7, the No. 1 EDG was again removed from service so that the licensee could perform additional detailed inspections of the air start system, including components such as the in-line strainers and related piping. During the time that EDG NO. 1 was out of service, the licensee identified that EDG No. 2 was not tested in accordance the the requirements of TS 3.8.1 (see Section 4.2.5). Rust fragments were found in the strainers and strainer plugs. The air start piping for both the left and right banks were removed to inspect for internal rust and debris, and for cleaning as necessary. A substantial amount of rust was removed from the inside of the piping. The No. 1 EDG was successfully retested on July 8 and was returned to service.

On July 11, the No. 2 EDG was taken out of service to clean both banks of air start piping in an effort to reduce the possibility for similar problems occurring on that unit. The provisions of TS 3.8.1 were satisfied during the time the EDG No. 2 was out of service. The amount of rust removed from that piping was about the same as was removed from the No. 1 EDG.

9.3 Summary

Previous plant modifications have been implemented to increase the reliability of the air start system. These include the addition of pulsation dampers and air start dryer units to absorb any rapid air pulses out of the air compressors and to remove moisture from the air used in the air start system. These modifications may have improved the quality of air currently used in the system, however, have been ineffective in preventing problems due to the effects of the previously degraded air system. The licensee has proposed several options to further improve system reliability: 1) periodically inspect the in-line strainers, and 2) install an in-line filter in the system.

The results of the vendor inspections of the ASMs and the determination of long term corrective actions will be reviewed during future inspections. This is an Unresolved Item (50-334/88-22-02).

10. Inadequate Cable Separation

During walkdowns of the Unit 1 and the Unit 2 cable spreading rooms, the inspector identified several instances of inadequate separation between cable of different safety trains. Cable separation is required to assure that a single failure or event could not impact more than one train of safety equipment. This requirement is found in the General Design Criteria (10 CFR 50, Appendix A), the ECCS criteria (10 CFR 50, Appendix K) and the Protection System criteria (10 CFR 50.55a(h)). At Beaver Valley, these requirements are documented in BVS-3001 for Unit 1 and 2BV-931 for Unit 2, with respect to cable separation. Individual tasks such as cable

installation, cable wrapping and cable tray cover installation implement the requirements which differ somewhat between the two units. These activities occur not only during construction, but also during outages as system modifications are performed. During normal plant operation, other activities such as maintenance or surveillance of nearby components have the potential to degrade separation by such things as damaging cable tray covers. The individual tasks associated with safety related equipment are required to be controlled to assure quality.

At Unit 1, the cable in tray 1TC5450 was not properly separated from the cable in tray 1TC306B. Neutral cable was found routed in tray 1TC6080 which then was routed touching cable routed in tray 1TC607P. In other locations, cable tray covers were absent such that the required separation between trays was not being maintained. Instances of spared cable were found such that the loose coils were stored in violation of separation criteria. These and other deficiencies were identified to the licensee for correction.

At Unit 2, a cover on conduit line 2CC940M was missing and the cable in the line was extruded such that there was inadequate separation with cable 2NNSANC457. A spare coiled cable exiting tray 2TC403P was found loosely piled together on the floor with cable 2NNSANC457 with no separation. Other deficiencies such as stray and missing tray covers were also identified to the licensee for correction. This is a violation (50-334/88-22-03; 50-412/88-16-02).

Licensee corrective actions were in progress at the close of the inspection, including additional walkdowns to look for other deficiencies. The identified deficiencies are similar to the items discussed in Sections 3.1 and 3.2 (previous Open Items). These findings, taken as a whole, are indicative of a programmatic weakness in the assurance of adequate separation of safety related cable.

11. Inoffice Review of Licensee Event Reports (LERs)

The inspector reviewed LERs submitted to the NRC Region I Office to verify that the details of the event were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following LERs were reviewed:

Unit 1:

LER 88-06: ESF Actuation Due to the Inadvertent Energization of Slave Relay K643B.

LER 88-07: Reactor Trip and Safety Injection Due to Reactor Coolant Pump Trip.

LER 88-08: Reactor Trip due to Low-Low Level in "A" Steam Generator.

LER 88-09: Reactor Trip and Feedwater Isolation.

LER 88-10: Incore Instrumentation Thimble Tube Wear.

LER 88-11: Thermal Shield Bolt Replacement.

LER 88-12: Feedwater Elbow/Nozzle Cracking.

Unit 2:

LER 88-08: Notification of Deficiency in ITE-51 Time Overcurrent Relays.

The above LERs were reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. Previous inspection reports have noted that while most LERs provided good documentation of event analyses, root cause determinations and corrective actions, some LERs were weak in that they contained event inaccuracies and safety evaluation omissions. All of the LERs reviewed during this inspection period were found to be good. LER report quality has been improving over the last several months. The inspector will continue to monitor LER report quality during future inspections.

12. Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted pursuant to Technical Specification 6.9 (Reporting Requirements) are reviewed. The review assessed whether the reported information was valid, included the NRC required data and whether results and supporting information were consistent with design predictions and performance specifications. The inspector also ascertained whether any reported information should be classified as an abnormal occurrence. The following reports were reviewed:

-- BV-1/BV-2 Monthly Operating Report for Plant Operations for May 1-31, 1988.

-- BV-1 Revised Monthly Operating Reports for March and April, 1988.

-- BV-1/BV-2 Monthly Operating Report for Plant Operations for June 1-30, 1988.

-- Unit 1 Cycle 7 Startup Test Report.

No deficiencies were identified.

13. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. Unresolved items are discussed in Sections 4.2.1, 4.2.6 and 9.

14. 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 on July 21, 1988.