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Licensee: Duquesne Light Company
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Facility Name: Beaver Valley Power Station, Unit 1

Inspection At: Shippingport, Pennsylvania

Inspection Conducted: March 21 - April 1, 1988

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Inspection Summary: Announced Team Inspection on 3/21-4/1/88 (Inspection Report No. 50-334/88-08)

Areas Inspected: An assessment was made of the reliability and availability of AC and DC power systems, diesel generators, emergency core cooling system and auxiliary feedwater system. A verification was conducted of the equipment and procedure adequacy for selected scenarios at the plant and at the simulator.

Results: One violation with two examples of failure to follow procedures and three unresolved items were identified; vibration monitoring program for pumps (paragraph 4); justification for not incorporating vendor recommendations in plant procedures (paragraph 5) and justification for the lower limit of 9.8 psia for containment pressure when considering the net positive suction head of the safety injection pumps (paragraph 6). Such strengths as senior management attention, knowledgeable staff, tracking system for plant equipment performance and high availability for the inspected systems were also noted.

TABLE OF CONTENTS

1.0 Introduction Inspection Scope and Summary of Findings

This inspection was conducted by a team of NRC inspectors to examine safety significant activities and equipment at the Beaver Valley Power Station Unit 1. The lines of inquiry used by the inspectors were based on generic Probabilistic Risk Analysis (PRA) insights, on the Surry PRA (NUREG/CR-4550/Vol. 3) which is a sister plant to Beaver Valley 1, and on operational experience data. This section describes the inspection methodology, the selected accident sequences, and the inspection areas that form the basis for the inspection. Section 1.3 summarizes the inspection findings and conclusions of the inspection and provides an index that leads the reader to the section of this report where the details of the findings can be found. Sections 2 through 7 describe in details the inspection activities, findings, and conclusions.

1.1 Inspection Methodology

As part of preparation for the inspection, the team made an assessment of the applicability of the Surry sequences to BV-1 by comparing the major design differences. The accident sequences generic to PWRs were also studied for applicability to BV-1. BV-1 electrical engineers were asked to review one sequence involving the loss of a 480V bus to determine its applicability. This review resulted in eliminating this sequence from consideration. Preliminary systems, components, and human actions were identified for inspection. Modifications to the list were then made based on the plants operating experience and past inspection findings and observations. Based on the above, a final list of systems, components, and human actions were selected which became the subject for inspection.

The inspection rationale was to evaluate the the availability of the selected components and the capability of plant staff to react and to recover from the selected emergency situations. Although the inspection's primary focus was on the "target" components and activities, programmatic aspects were also evaluated, such as management controls, oversight by quality assurance, training and human factors.

The degree of equipment availability as supported by the performance records, programs, activities, initiatives, observed conditions, and apparent level of personnel competence was qualitatively evaluated based on the following criteria:

- measures to prevent equipment deficiencies or failures (preventive maintenance, trending performance);
- prompt detection of failures or deficiencies (surveillance);
- effective correction of such findings (corrective maintenance);
- verification of equipment operability (post-maintenance testing, calibration, and operational check-off).

The NRC inspectors observed plant response to various simulated accident sequences at the facility simulator. Also, procedures were walked through with qualified personnel at the simulator, in the control room, at the switchyard, and in equipment areas. The operations were evaluated to ascertain that operators were familiar with the plant equipment and the associated plant procedures during normal, abnormal, and emergency situations. The event simulations were evaluated for the operator's ability to utilize control room or local indications, to understand manual and automatic features under the event situations, to use appropriate procedures, and to operate equipment locally and remotely, including alternate train operations. A particular inspection emphasis was to assure that proper emergency procedures (both symptom and event oriented) were available and capable of being effectively used during the accident situations. The procedures were evaluated for adequacy, technical accuracy, clarity, and consistency.

1.2 Selection of Accident Sequences and Inspection Areas

The two accident sequence classes listed below and their related equipment failures, human errors, and recovery actions were selected for inspection. These sequence classes were judged to be among the dominant sequences at BV-1.

(a) Loss of Offsite Power/Blackout Sequences

This accident sequence class is characterized by initiators that place the plant into a transient and at the same time degrade vital electrical supplies to varying degrees. This includes blackout sequences as a result of failure of both emergency diesels. Blackout may proceed quickly to core damage if a reactor pump seal LOCA, a stuck open PORV, or a loss of AFW occurs.

The inspection addressed this class of sequences by reviewing the human actions that would minimize long term losses of AC power. This involved inspecting the switchyard, emergency buses, fast transfer features, attendant breakers, and transformers. Emergency Diesel Generator availability and recovery actions were also reviewed. In addition, the use of the EOPs in stabilizing the plant under blackout conditions and in restoring AC power were tested by simulation. The auxiliary feedwater availability under blackout conditions was also evaluated.

(b) Small Loss-of-Coolant Accidents (LOCA)

This accident sequence class is characterized by a small LOCA as an initiator followed by failure of either high pressure injection or recirculation.

The inspection included simulations of the sequence on the plant simulator as well as a walkthrough of recovery actions at the facility involving initially failed valves or pumps. The equipment reviewed included the charging pumps, safety injection pumps, and the valves that must operate to deliver water to the reactor.

1.3 Summary of Findings

A. Strengths

Overall, the results of the inspection indicate good initiatives on the licensee's part to maintain at a very high level of availability of those systems, structures and components that have a potential to contribute towards core melt sequences. Management controls, programs and procedures are in place to assure continuation of the achieved high level of availability. Periodic audits by the Quality Assurance Organization verified the adequacy of the established programs by sampling activities directly related to equipment availability. The following strengths were noted in particular:

(1) Senior Licensee Management Involvement

The senior management of the licensee recognized the importance of maintaining the systems that are required to mitigate the consequences of accidents and initiated actions to further enhance effectiveness in this area. Reconstitution of design bases, Safety System Functional Evaluations and development of Unit Specific Probabilistic Risk analysis are some of the actions being implemented by the licensee.

(2) Knowledge of Personnel

The licensee has invested adequate resources to develop knowledgeable and well trained engineering, maintenance and operations personnel to provide day to day support in maintaining the required system reliability.

(3) Plant Equipment Performance Tracking

The licensee has developed and implemented the Maintenance Information Management System to track Maintenance Work Requests and to monitor and trend plant equipment performance.

(4) High Availability for Systems

The licensee's efforts, so far, resulted in high availability for the systems reviewed during this instruction. For example, the availability for diesel generators, safety injection pumps and the turbine driven auxiliary feedwater pump were 0.987, 1.0 and 0.987, respectively.

B. Violations

Two examples of failure to follow established administrative procedures were observed. These collectively constituted a violation (50-334/88-08-01) against Technical Specification 6.8.1. The examples were:

(1) On March 24, 1988 the inspectors observed that two seismic supports near valves 1DA-138 and 1DA-140 of the starting air system for Diesel General No. 2 were loose to the touch during power operation. The looseness was due to loose bolting. This required the Diesel Generator to be declared inoperable. The failure to identify the loose seismic supports was not consistent with licensee procedure OP-11, Control of Maintenance and Modification, Revision 7, Section 11.4.2, which requires that the acceptability of equipment is known throughout operation. (see paragraph 3.4 for details)

(2) There is no objective evidence to assure that preventive maintenance was performed on exhaust fans VS-F-22A&B and inlet dampers VS-D-22-2C&D at 12 month intervals since May 1986, as required by Table 1 of Preventive Maintenance Procedure (PMP) 1-44VS-VNT-1E (Revision 3). Additionally, the inlet and exhaust dampers VS-D-22-1A&B and VS-D-22-2A&B were not incorporated in the above PMP. (see paragraph 3.5 for details)

c. Unresolved Items

1. Inservice Testing Program for pumps uses a vibration monitoring system that yields inconsistent results. As a result the observed readings varied between 2 and 8 mils depending on the individual performing the test and location for monitoring. The licensee commited to review the current BV-1 vibration monitoring program to provide more consistent results. (see paragraph 4.2 of the Report for details) (Item 50-334/88-08-02)

2. There was no justification for not incorporating vendor and engineering department recommendations in the station maintenance and operating procedures. Specifically, the following engineering department authorized vendor

recommendations for the turbine driven auxiliary feed pump were not incorporated into the plant maintenance and operation procedures. (see paragraph 5.3 for details) (Item 50-334/88-03)

(a) Flushing of oil system for 4 hours
(b) Oil preheat to 110°F - 120°F
(c) Weekly testing of overspeed trip

3. Engineering justification for assuring that the safety injection pumps will have sufficient net positive suction head during the recirculation phase of an accident if the containment reaches 8.9 psia as allowed in the emergency operating procedures. (see paragraph 6.2 for details) (Item 50-334/88-08-04)

2.0 Normal and Emergency Electrical Power

2.1 Offsite Power Sources

The loss of offsite power was identified as a dominant contributor to core melt in the generic PRA. The inspection objectives were to review the reliability of the offsite power sources and their connection to station emergency electrical systems and to assure station personnel are capable of recovering from postulated equipment failures. The offsite electrical power source of Beaver Valley Unit 1 (BV-1) is fed from the following 138 kV transmission lines:

a) Crescent (Z-28, Z-29)
b) Crucible (Z-33, Z-31, Z-32)
c) Midland (Z-30)
d) Valley (Z-37)

In addition, BV-1 offsite electrical power source can also be fed from the following 345kV transmission lines through the 345/138kV transformers located in the BV switchyard:

a) Saminis (#312)
b) Collier (#314)
c) Mansfield (#316)
d) Hanna (#320)

The incoming offsite power sources are connected to the BV-1 station through 138kV circuit breakers #92 and #83. These circuit breakers are oil cooled, 3-phase breakers with hydraulic actuation, and are located in the BVPS switchyard. Transmission lines from these breakers are fed to two system station service transformers (SSST) #1A and #1B, which are located at a different corners of BV-1 plant. The circuit breakers are normally closed and the SSSTs are normally energized. Protection and tripping of circuit breakers #92 and #83 are powered by two independent 125 VDC sources, one from BV-1 and the other from the battery in the switchyard building. The protection circuits are designed such that the trip coils are energized to trip the breakers. There are two control switches in the BV-1 control room to manually operate trip coil #1. Trip coil #2 is operated by the protection circuits in the switchyard building. No manual switches are provided in the switchyard building to minimize unauthorized tripping of the circuit breakers. In the unlikely case that the trip coils cannot be deenergized through remote (electrical) operations, the breakers can be closed by manual operation of the mechanical devices located in the circuit breaker control cubicles. This process involves slow closure of the circuit breakers. The power to the breakers must first be removed (to prevent serious arcing) and later restored after the circuit breakers are closed. Removing and restoring power to the circuit breakers can be achieved by the automatic switching actions from the network operating computers in Racoon, Pennsylvania. To demonstrate the feasibility of this process and to estimate the time required for this manual operation, the inspector walked through the licensee's response drill to the following assumed scenario on March 29, 1988:

a) BV-1 turbine tripped
b) circuit breakers #92 and #83 both tripped open
c) both circuit breakers could not be closed from BV-1 control room
d) both circuit breakers could not be closed electrically from the switchyard
e) no actual switching needed to take place during the drill
f) the substation personnel were nct informed in advance of this drill

The drill phone call was initiated by BV-1 control room by the nuclear shift supervisor. The first substation operator arrived at the switchyard 27 minutes after the initiation of the call. Three more substation personnel arrived at approximately 5 minute intervals. The substation operators demonstrated the process verbally. The inspector estimated that it takes about 50 minutes to restore power to both 138kV buses. The inspector concluded that the overall response was adequate for the assumed scenario.

The inspector also reviewed the maintenance and inspection program of the SSSTs, the unit station service transformers (USST) and the main transformer. For each transformer, the following inspection and maintenance are periodically performed.

a) once a shift: record oil level, winding temperature and oil temperature

b) once a month: a syringe of oil sample is sent to the off-site laboratory for routine analysis

c) once a year: 2 quarts of oil sample are sent to the off-site laboratory for more detailed analysis, including dissolved gas contents dielectric tests of the oil sample.

d) once every outage: Doble electric tests to verify the integrity of the insulation, associated protective relay test, clean bushing and radiator

High voltage circuit breakers #92 and #83 and the two 345/138kV automatic transformers (all located in the switchyard) are maintained and inspected by the Transmission and Distribution Division of DL Co. The inspector walked down the major components of the switchyard. The circuit breakers, the auto transformer and the protective relays appeared to be well maintained. The inspector reviewed the maintenance records of the transformers and breakers associated with the offsite power supply system over the last 2 years. These records indicated that routine maintenances were performed on these devices.

2.2 AC Distribution System

The inspection objectives were to verify the reliability of the 4160 volt system which included 4 non-vital buses (1A, 1B, 1C, 1D) and 2 emergency buses (1AE and 1DF), breakers and transformers associated with these buses.

2.2.1 4160 Volt AC System

The onsite 4160 volt power system includes the transmission lines of 22kV output from the main generator, two USSTs 1C and 1D, 4kV circuit breakers as well as the power supplies from the 138kV input from the switchyard. When the main generator is operating, the station power is supplied from the generator through the two USSTs, and four 4kV circuit breakers 41C, 141C, 241D and 341D. When the main generator trips, power supplies are transferred to off-site power by opening circuit breakers 41C, 141C, 241D, 341D and closing circuit breakers 41A, 141A, 241B, 341B. The transfer takes place within 0.15 second by means of the fast transfer system.

Emergency buses 1AE and 1DF receive their normal power from 4kV buses 1A and 1D respectively. Bus 1A supplies emergency bus 1AE through two series connected circuit breakers (1A10 and 1E7). Bus 1D supplies emergency bus 1DF in a similar manner through circuit breakers 1D10 and 1F7. Series connected circuit breakers are utilized to provide redundant protection of the diesel generator against overload. Tripping of either breaker in this series arrangement isolates the emergency bus from its normal power supply. In the event of a loss of normal power to either or both emergency buses, these buses will be automatically supplied by their associated diesel generators.

2.2.2 480 Volt AC System

The 480 volt AC system supplies 480 volt ungrounded power to various 480 volt pump and fan motors, motor operated valves, and heaters throughout the plant. In addition, it supplies an alternate source of power to the 120 volt AC vital buses.

The 480 volt AC system consists of seven 480 volt substations, each fed through two transformers from various 4160 volt buses. Substations 1-1 through 1-5 are non-vital buses. Substations 8N and 9P are vital buses, and are fed from the 4160 volt emergency buses through stepdown transformers. Each of the 5 non-vital substations consists of two buses, connected with a bus tie breaker. The 480 volt bus tie breakers facilitate automatic 480 volt bus transfer in the event that either of the adjacent 480 volt buses should incur a loss of voltage.

The substation buses supply power through circuit breakers, directly to large 480 volt motors and heaters, and through motor control centers (MCC) to smaller 480 volt loads. There are 46 MCCs, 14 of these are powered by emergency buses. The MCCs supply their loads to electric equipment through circuit breakers and starters.

All 4160/480V substation transformers are General Electric indoor, dry type transformers, some are self-cooled, while others are fan cooled. All substation circuit breakers are General Electric AK type, 3-pole, single throw, electrically operated, drawout type with power sensor or dual magnetic overcurrent trips.

2.2.3 Circuit Breaker Maintenance Program

The BV-1 electrical maintenance group is responsible for both preventive maintenance (PM) and corrective maintenance (CM) of all in-house 4kV and 480V circuit breakers. The high voltage circuit breakers (138kV and 345kV) in the switchyard are maintained by the Transmission and Distribution of Duquesne Light Company. The frequency of the 4kV circuit breaker PM is scheduled at each refueling outage, or once every 12 months if the breaker can be removed during power operation. The maintenance activities require the breaker to be removed from the cubicle and include 1) arc chute maintenance, 2) buffer inspection, 3) contact inspection, 4) contact pressure check, 5) contact sequence check, 6) contact resistance test, 7) insulation resistance check, and 8) routine cleaning of breaker and cubicle housing. The maintenance activities are prescribed in maintenance procedure No. 1-36SS-BKR-1E, "ITE 4kV 1E Breaker Inspection", Revision 8, dated June 5, 1987. The inspector witnessed the maintenance activities for circuit breaker ACB-1E-15, which supplies power to Charging High Head Safety Injection Pump CH-P-1C, and did not identify any deficiencies.

The frequency of the 480V circuit breaker PM is 12 months or at each refueling outage. Maintenance activities are similar to that of 4KV breakers, and are prescribed in the following PM procedures.

PMP No. 1-37SS-BKR-1E, "480V Circuit Breaker Inspection, General Electric AK-3A-25" dated January 8, 1988.

PMP No. 1-37SS-BKR-2E, "480V Station Service System Supply Breaker Inspection, AK-3A-50S" dated January 8, 1988.

PMP No. 1-37SS-BKR-3E, "480V Circuit Breaker Overcurrent Protection Test" dated September 9, 1987.

PMP-No. 1-37SS-BKR-4E, "480V Station Service System Supply Breaker Inspection" dated January 8, 1988.

PMP No. 1-37SS-BKR-5E, "480V Circuit Breaker Inspection, ITE K-LINE" dated September 9, 1987.

The inspector witnessed selected portions of the maintenance activities performed on breaker No. 3E10, which serves "Bus 1E-IF Tie". No deficiencies were identified.

The PM activities for the high voltage circuit breakers at the switchyard are performed by the Transmission Distribution Division. These breakers are maintained at 18 month frequency. Maintenance activities include contact resistance check, timing test, operating mechanism inspection, power factor test, field oil test, and Doble test. The inspector reviewed the maintenance records for 138KV breaker #83 dated July 25, 1986 and December 5, 1984, and for 138KV breaker #92 dated July 23, 1986. No deficiencies were identified.

2.3 DC Distribution and Battery Systems

The safety objective of the station batteries is to supply all normal and emergency loads for the DC power components. In case of a station blackout, the DC battery system is required for the functioning of safety or accident mitigation components and systems such as breakers, valve operators and inverters. The DC system is also relied upon to provide essential monitoring and indicating functions. The inspection focus was on battery availability with emphasis on possible common cause failure which might affect the battery systems.

The DC system consists of five 60-cell batteries and battery chargers. Four of these batteries are 1E batteries (batteries 1-1 through 1-4) and the fifth is non-1E (battery 1-5). Each battery is connected to the 125 VDC bus through a circuit breaker. All five battery chargers receive their power from 480V vital buses. The non-1E battery can be connected to either bus 1-1 or bus 1-2 as a backup, if required. Each vital DC bus is provided with a 20 KVA inverter, which converts 125VDC to 120 VAC to a vital instrument bus through a circuit breaker. The vital instrument bus supplies power for safety related instrumentation and control applications. Each vital instrument bus is provided with a static switch which connects instantly to a normal 120 VAC power supply should the vital instrument bus lose power (e.g. inverter failure).

Each 1E battery is housed in a separate battery room with controlled access in the switchgear area. Each battery room is ventilated with 500 cfm exhaust flow provided by redundant exhaust fans VS-F-16A and VS-F-16B to avoid hydrogen accumulation. A flow switch is located in the exhaust duct to actuate an alarm should the air flow drop below its setting. The non-1E battery is located in the switchgear area.

The inspector walked through all four 1E battery rooms and the non-1E battery area. The battery rooms and battery area were found to be clean and did not contain combustible materials. The electrolyte in the battery cells were at the correct levels, the intercell connection bars were clean and the room temperature was around 78°F. The inspector also noticed that the ventilation system was providing the required air flow to maintain hydrogen at an acceptable level in the battery rooms.

The required preventive maintenance of the four 1E batteries are prescribed in BV-1 procedures MSP 39.01, MSP 39.02, MSP 39.03, MSP 39.04, for Test and Inspection of Battery Nos. 1, 2, 3, 4, respectively. The maintenance and surveillance activities include:

Once/Shift: Walk through all battery rooms by operations personnel.

Weekly: Specific gravity and temperature check on pilot cell of each battery.

Quarterly: Check specific gravity and temperature of all cells, check electrolyte level of each cell, check intercell connection resistance of 10% of the cells, clean top of each cell, and pilot cell voltage check.

Yearly: Check intercell connection resistance of all cells.

The inspector observed the quarterly maintenance activities on Battery No. 4 on March 23, 1988. While measuring the specific gravity and temperature of cell No. 10, the licensee's maintenance personnel observed the temperature readings on the digital hydrometer differed more than 4½°F compared with the reading on the glass thermometer. The procedure allows a ±2°F deviation. The thermometer was calibrated on the same day. The licensee could not determine the problem and the test was discontinued. On the next day the licensee informed the inspector that the problem was due to a very fine crack on the glass thermometer. A newly calibrated thermometer was borrowed from BV-2 and the quarterly maintenance activities were completed.

2.4 Solid State Inverter

Beaver Valley Unit 1 has four solid state inverters installed which convert 125 VDC to 120 VAC to supply four vital buses used for the safety related instrumentation and control system loads. The licensee's long standing problem with the reliability of the Number 3 vital bus became a focal point for this inspection.

Buses 3 and 4 have inverters manufactured by Cyberex Corporation. Initially, Number 3 inverter started blowing fuses to clear the phase to phase shorts resulting from improper commutation of the silicon controlled rectifiers. The fuse problems became more frequent with time. When the failures resulted in two reactor trips the licensee initiated a major effort to solve the problem. (The inverter for bus number 4 never exhibited a comparable problem).

The effort was a multi-phase approach which consisted of a symptom oriented cure and a root cause investigation to determine why the fuses were blowing. Ultimately, the installation of static transfer switches to provide alternate AC power to all vital buses assure system reliability. The static switches were installed and tested during this past outage. Both the licensee and the manufacturer have done extensive testing on both of the Cyberex units. In addition, over the last two years of testing Cyberex has practically rebuilt the Number 3 inverter. The results of the testing so far indicate that the inverter is functioning properly. However, operational problems continue to occur with the No. 3 vital bus.

The licensee now feels that some unknown anomaly is causing the silicon controlled rectifiers to trigger out of sequence. They have been reluctant to do extensive testing of the systems before the installation of the static switch was complete as they might risk losing the Number 3 vital bus and initiate a plant scram. The licensee is in the process of acquiring high speed recorders and will be looking for voltage and current spikes. The root cause investigation is on-going.

The installation of the static switches, as previously stated, will transfer supply for the 120 VAC vital buses to an alternative source of AC power which is backed up by the emergency diesel generators. This provides a reasonable level of reliability for the 120 VAC vital buses pending root cause determination.

2.5 Availability of the off-site power sources

The licensee provided the inspector with the availability records of the BV-1 offsite electrical power sources for the period from the beginning of 1984 to March 28, 1988. The following power transmission line interruptions were caused by thunderstorm:

BV 138KV Circuit Outages

Date	Time Out	Time In	Circuit Name	Ckt. No.	Minutes Out
7-20-86	1527	1527.1	BV-Crescent	Z-29	.1
7-29-86	0027	0027.1	BV-Crescent	Z-29	.1
7-29-86	0101	0102	BV-Crescent	Z-29	1.0
11-17-87	1406	1407	BV-Midland	Z-30	1.0

The offsite power supply to BV-1 was not affected by the above transmission line interruptions because of the multi-power supply source arrangement. (see paragraph 2.1 above)

2.6 Conclusions

The results of this inspection indicated that BV-1 has reliable off-site power sources due to the flexibility of its design, and that its maintenance program for critical electrical equipment was adequate. The licensee has established adequate preventive and corrective maintenance programs to assure continued reliability of the normal electrical power system and its components. Through witnessing of ongoing maintenance and engineering activities and simulated drills, the inspectors concluded that the licensee personnel were knowledgeable in the requirements of this system and were adequately trained.

3. On-site Emergency AC Power Supply/ Emergency Diesel Generators

The loss of offsite power in conjunction with failure of the emergency diesel generators was identified as a dominant accident sequence in generic PRAs. This sequence could result from a common mode failure to both diesels or the failure of a single diesel while the other one is out for maintenance. For these reasons, the inspector examined various aspects of the emergency diesel generator system including potential common mode failures and failures of supporting systems including faulty maintenance which could trigger a failure of the diesel or electrical power distribution buses. In addition, component failure histories and maintenance work requests were reviewed to identify and investigate failure modes for this system.

The following areas and components of the emergency diesel generator and its associated AC distribution buses were inspected:

- AC switchgear
- Controls and instrumentation
- Fuel oil system
- Starting air systems
- Emergency diesel rooms
  - Fire barriers
  - HVAC
  - Supply of combustion air
- Cooling water system
- Testing
- Maintenance

The emergency diesel generator system consists of two independent 20 cylinder "V" block turbocharged diesel engines directly coupled to synchronous generators equipped with regulated static exciters. Each diesel generator combination is rated for 2850 KW continuous duty and supplies backup power to one of the two emergency buses if normal power is lost. Loads on these emergency buses are considered essential for coping with possible accident scenarios and for the safe shutdown of the nuclear reactor.

Visual inspections of the emergency diesel rooms were conducted to assess the general condition of the equipment, as-built location, proper identification, ambient environmental conditions, accessibility for maintenance, and station administrative controls regarding housekeeping and fire prevention. These visual inspections included detailed walkdowns of the air starting system, including newly installed air dryers, newly installed pulsation dampers, the fuel system, and the fan units and dampers which provide room cooling and admission of combustion air.

3.1 Surveillance Testing

The inspector witnessed licensee performance of surveillance tests of the emergency diesels in order to ascertain procedure quality, operator ability and competence, and familiarity with the equipment. Conduct of the test revealed a leaky check valve in the water to the water heat exchanger used for engine cooling. The licensee stated that the valve had been repaired during the outage, but still leaked. The inspector raised a concern about the adequacy of post maintenance testing. The inspector reviewed maintenance test procedures and test records and subsequently determined that inadequate post maintenance testing is not a concern at Beaver Valley 1.

The inspector witnessed the conduct of selected surveillance, calibration, and maintenance procedures. In each instance, the personnel involved had a good grasp of what the procedure was intended to demonstrate. The licensee provides on the job training and formal classroom training for the maintenance personnel. They demonstrated an excellent understanding of the equipment they were working on, did a thorough and complete job of executing the procedures and exhibited competence in the use of required test equipment. In general, the quality of the procedures is satisfactory.

In addition, the inspector examined the fire barrier separation between the two emergency diesel generators, the room cleanliness, testing methods for the diesel control logic and instrumentation. These areas were found to be satisfactory.

3.2 Starting Air System

Beaver Valley Unit 1 has had a history of problems with their emergency diesel generator air starting system. These problems include the failures of the high pressure air compressors, system check valves and air start motors. The primary causes for these problems has been traced to pulsations in the air flow inducing system resonances and high moisture in the air leading to rust buildup in the air motors.

Pulsations in the air line causes rapid check valve failure which bleeds air from the air storage tanks. If both air storage banks are lost, one diesel generator becomes inoperable. Technical Specifications require that the system be returned to service (emergency diesel generator operable) within 72 hours or be in cold shutdown (Mode 5) within the next 36 hours. The licensee's solution to the problem was to install a pulsation chamber off each compressor and to use two smaller diameter redundant check valves downstream of the pulsation chamber.

Moisture in the air has resulted in rust and scale in the air start motors which has rendered the motors inoperable. The licensee installed air driers on the starting air system during this past outage. The inspector conducted a detailed walkdown of the redesigned starting air system and observed its operation on three separate occasions, including the venting of the moisture collecting tanks. Air flow pulsations at the check valves were barely discernable, and no moisture was observed during the venting process. The inspector had no further questions in this regard.

3.3 Fuel System

The walkdown of the diesel fuel system was undertaken with an emphasis on potential for common mode failures. Fuel is brought on site and unloaded into an underground holding tank inside the protected area. It is then tested before it is pumped into two 20,000 gallon underground tanks, also inside the protected area, which supply each diesel's day tank via redundant transfer pumps.

This procedure seems adequate to preclude a common mode failure resulting from delivery of bad fuel. Also, the location of the underground tanks and the associated fill and vent piping inside a locked cage within the protected area provide reasonable protection against tampering.

The inspector determined that the calibrated instruments used to verify tank level in the 20,000 gallon tanks did not have identification tags to match their assigned "mark" numbers. In addition, the associated surveillance procedures did not use these identification numbers in the step which verifies adequate fuel supply.

The diesel engine is provided with a pressure switch which provides a signal in the event of high crankcase pressure. High crankcase pressure could be an indication of a failed piston or rings. These instruments were observed during the walkdown to not have identification tags or calibration stickers. The inspector's concern was that they may not be included in the licensee's instrumentation calibration program. This concern was resolved when the licensee produced recent calibration data sheets and attached identification tags. The licensee was in the process of attaching calibration stickers at the time the inspection ended.

3.4 Diesel Generator System Walkdown

The inspector walked down the major diesel generator systems to observe the physical condition of the components, instrumentation, and controls. Systems included in the walkdown were the diesel fuel oil storage, fuel oil delivery, lubricating, cooling, and air-start systems. Also included was the electrical cabinets and other equipment contained in the diesel rooms including the HVAC system.

The housekeeping in the diesel rooms was good showing a high degree of cleanliness and good control of combustibles. Comparison with the plant drawings did not indicate any discrepancies. All locked valves were checked, and were verified to be correctly positioned and locked. Two of the locked closed valves were determined to be inadequately locked. These were the locked crossties between the two banks of the starting air systems (valves 104 and 134). These are 2" ball valves with lever action handles, with a lock and chain that could be pushed away and the valve moved to the open position. This was brought to the licensee's attention for correction. The licensee agreed to review this concern.

On March 24, 1988 while inspecting the Diesel #2 starting air system seismic supports, it was observed that two seismic pipe supports near valves 1DA-138 and 1DA-140 were loose to touch. The licensee representative accompanying the inspector immediately reported this discrepancy to management. The Shift Supervisor appeared within five minutes and made a conservative decision to declare the diesel inoperative. A surveillance test of Diesel #1 was conducted within 50 minutes after the declaration. The inspector observed the test which was successful.

The licensee determined that the pipe supports, in all likelihood, had been loosened while doing welding on the air start piping. The supports were not tightened after this procedure. This is considered poor implementation of return-from-maintenance procedures and is an example of a violation against Technical Specification 6.8.1 regarding implementation of procedure and licensee procedure OP-11, control of Maintenance and Modification (Revision 7) Section 11.4.2 which requires that the acceptability of equipment is known throughout operation. (50-334/88-08-01).

3.5 Emergency Diesel HVAC System

The Ventilation System has two fans VS-F-22A&B. Each of the fans has two inlet dampers (VS-D-22-1A&B, C&D) and two outlet dampers (V-D-22-2 A,B,C&D).

The dampers and exhaust fans installed in the diesel rooms are required to operate to assure adequate combustion air to the engines and to maintain room temperature below 90°F, which protects the temperature sensitive controls. The proper operation of this equipment is considered essential to diesel operation; they do appear on the Master Equipment List indicating that the licensee considers them Category 1.

The inspector determined that the monthly diesel test assures that the operation of the inlet dampers and the exhaust fans are observed and recorded. In addition, the equipment routinely operates to control and maintain diesel generator room temperatures, and its misoperation can be observed during daily operator rounds (except during cold weather). The dampers and fans were observed to operate by the inspector during a start test of DG1 on March 24, 1988 and also during the monthly surveillance test of DG2 on March 30, 1988.

The inspector reviewed the PM on these dampers and fans. PMP No. 1-44VS-VNT-1E, Revision 3, effective date May 13, 1986, which requires the preventive maintenance for a number of dampers and fans for BV-1 was reviewed. It was found that the exhaust fans and two of the four inlet dampers (VS-D-22-2C&D) are listed as requiring PM on a 12 month schedule. The inlet and exhaust dampers (VS-D-22-1A&B, VS-D-22-2A&B) were not found in the PMP. Initial interviews with maintenance personnel indicated that no PMs have been conducted for any of this equipment. Subsequent interviews revealed that linestarter maintenance was being conducted. The inspector verified that PMP No. 1-37SS-LINESTARTER-1E, that cleans and inspects the linestarters, was being done on MCCs E7 and E8 that feeds the dampers and fans. Further discussions with a maintenance supervisor indicated that PM on these types of dampers and on small motors (about 30 hp) are not done until an operational problem becomes evident. In the case of the damper and fans in question, the maintenance department determined that PM was not necessary; it was not evident that the procedure group nor other licensee organizations were made aware of or concurred with this determination.

Based on the above observations and discussions the inspector concluded that an administrative control weakness exists relative to determining and controlling PM at BV-1. The 12 month PM frequency on the diesel room dampers and fans was determined by the licensee to be required. The On-site Safety Committee (OSC), the Maintenance Supervisor, and plant management approved this requirement. At some point, Maintenance excluded this PM requirement, resulting in the PM being missing from the computer generated maintenance schedule. This exclusion was not communicated to the procedure writer and was not concurred in by the OSC or management.

Thus, Maintenance can and does eliminate PMs without concurrence or knowledge of other organizations. One result of this is that PM procedures may not accurately reflect the actual PM program as evidenced in the case of the diesel HVAC equipment. This is an example of a violation of Technical Specification 6.8.1 and licensee procedure PMP No. 1-44VS-VNT-1E, Revision 3. (50-334/88-08-01)

3.6 Diesel Generator Availability

The inspector reviewed the INPO performance indicator data for the BV-1 diesels for the years of 1985, 1986, and 1987. In addition the NPRDS data base information form 1983 to 1987 was reviewed. The inspector also performed a detailed check of the control room logs for 1987 to verify the outage times for that year. The INPO performance indicator data was determined to be the best source. anverage availability calculation was performed based on the three years of INPO data. During that time, Diesel 2 failed to start because the internal linkage in the governor was not properly reset requiring governor replacement (failure date 8/27/85). Based on this one failure and a total of 257 hours out of service for both diesels, an average diesel availability for the three years of 0.987 was calculated. This does not include the scheduled maintenance periods during refueling outages. There were no indications that this level of availability will degrade in the future, based on our visual observations of the equipment and detailed review of maintenance history.

3.7 Conclusions

Based on this inspection it is concluded that the onsite emergency AC power supply system is designed and maintained to provide high reliability. Except for the procedure adherence problems, the licensee has established adequate procedures to assure continued reliability for this system. The engineering, operations and maintenance personnel supporting the day to day care of this system appeared to be knowledgeable and adequately trained.

4.0 Emergency Core Cooling System

The high head and low head safety injection systems were selected to assess the adequacy of the licensee's ECCS system performance during accidents that could lead to core melt. The loss of the high head (HH) and low head (LH) safety injection (SI) systems during both the injection and recirculation phases following an accident were reviewed during this inspection based upon their relative importance to safety with respect to accident mitigation. The principal components of the HHSI system which provide emergency core cooling following a loss of coolant accident are the three centrifugal charging pumps (two operating plus an installed spare). Two separate and redundant trains comprise the HHSI system. The LHSI system also consists of two separate trains, each utilizing an independent LHSI pump. The LHSI pumps are physically located in the Safeguards Area outside, but adjacent to the Containment Building, with the pump impellers located within an extension of the containment boundary. Both the HHSI and LHSI systems deliver water from the refueling water storage tank (RWST) to the reactor coolant system (RCS) during the injection phase following an accident. When a preset low water level in the RWST is reached, the recirculation phase of the SI system is automatically initiated. Specifically, the water collected in the containment sump is recycled back to the RCS when the LHSI pumps transfer their suction to the sump, and either provide the recirculation flow directly to the RCS or supply suction flow to the charging pumps for high pressure recirculation back to the RCS.

4.1 Charging System

The normal system alignment for the charging system specifies that two charging pumps be aligned and available with the third pump (the installed spare) in the pull-to-lock position. Plant Technical Specifications require that two separate and independent ECCS subsystems shall be operable, with each subsystem consisting of one operable centrifugal charging pump and associated operable flowpaths. Over the lifetime of the plant, cracked or broken shafts and mechanical seal failures/leakages have been the major reasons for individual charging pump unavailability. However, the licensee has been able to benefit from the use of the installed spare charging pump from an availability standpoint, in that the third charging pump may be placed in service only minutes following a failure of one of the two operating charging pumps. During 1987, the two operating charging pumps had an availability of 100%.

Although the licensee has not experienced unavailability problems with the charging pumps, the pump operational problems that were previously experienced at BV-1 have received considerable licensee and vendor attention. A metallurgical examination, performed for the latest charging pump shaft failure (December 1986), identified the root cause for failure to be high cycle medium stress rotating bending fatigue. Several licensee initiated corrective actions (including hardware modifications) were subsequently developed to resolve the potential pump problems and prevent future failures. The licensee expects that recent vendor design changes for charging pump components, licensee initiated design modifications and improved maintenance techniques will also increase system reliability.

Selected support systems were also reviewed with respect to the charging system. In particular, the inspector reviewed the operational and maintenance histories associated with charging pump lubricating oil coolers. The oil is cooled by the river water (RW) system. Upstream of the coolers are two RW strainers, one on each of the two, six inch supply lines. A review of the maintenance history identified that only a few instances of clogged lines have previously occurred (one of the two lines was clogged once in 1983 and once in 1987). The licensee periodically inspects and cleans the strainers (usually weekly or biweekly, depending upon river conditions and inspection results). A design change package was partially completed on the system, which will ultimately incorporate a local differential pressure indication across each of the strainers. The piping has already been installed, but the pressure gauge has not. The licensee expects to complete the modification by the end of 1988. Implementation of the modification will provide more precise criteria for predicting strainer failure and incorporate the appropriate preventive maintenance to prevent charging system failures.

The inspector reviewed the licensees Preventive Maintenance (PM) Program with respect to the charging pumps. The frequencies of the associated activities appear to be based upon both vendor recommendations and component performance histories. The inspector observed portions of selected PM activities, including PM procedure Nos. 1-7CH-P-1B-4M, Charging Pump Speed Increaser Lube Oil Pump Coupling Inspection and 1-7CH-P-1B-5M, Charging/High Head Safety Injection Pump Lubrication Maintenance. No deficiencies were noted during observation of the above.

4.2 Safety Injection System

Inspector reviews of failure data for the LHSI pumps indicate that pump failures and down time have been few, and pump availability is therefore relatively good. The inspector reviewed recently completed (1987) Operations Surveillance Tests (OSTs) for both LHSI pumps. The review identified that vibration readings from month to month sometimes varied by a factor of four (i.e. between 2 and 8 mils). The Technical Advisory Group trends specific operational parameters, including vibration, per the Inservice Testing (IST) Program requirements. A review of the trending information determined that with such erratic vibration results, adverse performance trends with respect to vibration may not be detected in a timely manner.

The inspector reviewed the training techniques and equipment used associated with obtaining vibration data for the LHSI pumps. The training associated with the equipment is primarily provided through the On the Job Training Program. That is, Operations personnel, who are responsible for taking the IST data during the performance of the associated periodic OSTs, are instructed by experienced personnel on the use of the measuring equipment. The current vibration measurements for the LHSI pumps quantify shaft displacement (mils). Variations in vibration results may occur depending upon differences in location and movement of the instrument during the data taking activities. The licensee has been unable to provide permanent markings on the shaft to ensure that the location is consistent.

Following a plant trip and SI actuation on August 29, 1985, a plant shutdown to Mode 5 (Cold Shutdown) was required due to the failure of the O-ring and gasket arrangement on several of the nine control rods that penetrate the casing of each LHSI pump. The control rods were added as part of a modification in 1980 to adjust wedges that are intermittently spaced along the deep shaft pump casing to dampen any vibration during a seismic event. NRC Unresolved Item No. 50-334/85-18-02 was previously opened to review the licensee's corrective action associated with the pump failures. The licensee felt that a contributing cause of the failure was the loosening of the securing nuts which keep the wedge control rods in place. The licensee subsequently implemented a PM activity (PMP No. 1-11-SI-P-1A-1B-1M) to ensure that the securing nuts are tight. The PM procedure is performed on an annual frequency. The inspector noted that neither the vendor manual nor the PM procedure referenced torque values for the securing nuts. The licensee committed to consult the pump vendor to develop torque values for the securing nuts.

As stated above, the licensee determined that the control rod securing nuts are loosening. This may be attributable to excessive pump vibration. With the presence of a potential pump vibration problem in conjunction with erratic vibration results (and consequently, questionable trending information), a true vibration problem could potentially render both LHSI pumps inoperable without prior detection of degraded performance. The licensee acknowledged the inspector's concern, and subsequently committed to implement new, more precise vibration monitoring methods. The current submittal for the second ten-year IST Program for pumps at BV-1 is based on Subsection IWP of the ASME Boiler and Pressure Vessel Code, Section XI, 1983. The Code requires that quarterly vibration readings be performed and measured in mils. The licensee recently submitted a relief request, stating that the mechanical characteristics of a pump can be better determined by taking vibration readings in velocity units (in/sec) than by the current displacement (mils) methods. Additionally, velocity units are more sensitive to small changes that are indicative of developing mechanical problems and are therefore more meaningful than displacement measurements. A relatively large number of pumps were included in the relief request. However, the LHSI pumps were not. Therefore, the licensee committed to include the LHSI pumps, if practical, so that they also use velocity methods to obtain vibration data. For the short term, the licensee stated that velocity measurements (in addition to the displacement measurements) will be taken until a formal relief request can be processed. Implementation of the licensee's commitment will be reviewed during a future inspection.

Although the more precise velocity measurement technique is currently planned to be implemented by the licensee, the potential for erratic readings still exits, particularly when the deep shaft design of the LHSI pump is taken into consideration. The pump vendor manual specifies a maximum of 15 mils for vibration displacement. However, it appears that the licensee ensure that the velocity measuring devices allow the individuals involved to obtain consistent readings, assuming no significant changes in pump performance characteristics occur. It should be noted that BV-2 utilizes permanently installed vibration equipment, which eliminates the introduction of personnel error while obtaining data. The licensee representatives acknowledged the above observation and agreed to review the feasibility of using the BV-2 vibration monitoring technique at BV-1. This is an unresolved item (50-334/88-08-02).

4.3 ECCS Valve Availability

The inspector selected 11 ECCS valves in the charging and SI systems whose functions appeared to be safety significant. The accessible valve were visually inspected. Additionally, surveillance, maintenance and operating histories and related data were reviewed.

The review of MWRs for the past five years indicate that relatively few valve problems have occurred. Based upon system design and configuration, the nature and frequency of the valve problems reviewed indicate that overall charging and SI system availability is adequate because redundant and alternate system flowpaths allow for diverse methods for accomplishing the desired safety functions. Boric acid buildup on specific safety related valves, as noted on several MWRs, could potentially impact valve operability. However, the licensee has generally identified and corrected such problems in a timely manner, and valve and related system operability concerns have not been identified.

The licensee trends performance of valve operability checks in accordance with the IST Program. The inspector reviewed the licensee's internal semi-annual reporting system regarding valve trending data. The inspector determined that adverse trends could be adequately identified in a timely manner, and that licensee concerns with respect to potentially degraded valve performance have been identified, noted and ultimately resolved. These semi-annual trending reports include both the results of surveillance testing and maintenance performed on the associated valves. The inspector concluded that the selected valves have demonstrated acceptable availabilty.

4.4 Charging Pump Availability

The availability of the three charging pumps appear to be acceptable. From 1983 thru 1987 two failures have occurred. Pump CH-P-1C failed on April 5, 1985 due to bearing overheating. Pumps CH-P-1B failed on December 14, 1986 due to a broken shaft. The first failure was assumed to be a latent failure detected during startup from a standby condition whereas the second failure was detected immediately during pump operation. The failures were estimated to result in a total of 624 hours of effective outage time. No outage time due to minor corrective maintenance was determined. The shift supervisor shift turnover check lists do not indicate when the locked out charging pump was out for maintenance as no technical specification LCO is entered. Based solely on the two failures an average availability is calculated to be 0.995. The inspector found no indication that this level of availability would degrade in the future.

4.5 Safety Injection Pump Availability

These pumps have maintained high availability as evidenced by having no reported failures based on five years of NPRDS data. In addition the review of control room logs for 1987 show no instances where these pumps have been removed from service.

4.6 Conclusions

The review of the ECCS functions of the Charging and SI systems attempted to address the critical systems and components whose proper functioning are essential with respect to accident mitigation. Generic or significant repetitive problems were not identified during the inspection in this area. Inspite of the unresolved item discussed in paragraph 4.2, the inspector found that the ECCS equipment reviewed, including safety related pumps and valves, have adequate availability, and therefore, provide sufficient assurance of their ability to perform their required ECCS functions.

5.0 Auxiliary Feedwater System

The safety objective of the auxiliary feedwater system is to supply feedwater to the steam generators following a reactor trip. In the event of the loss of off site power and the failure of both emergency diesel generators the turbine driven auxiliary feedwater (TDAFW) pump provides water to the steam generators which then act as the heat sink for the decay heat of the core. The inspection focus was on the TDAFW pump availability with emphasis on possible component failures which might affect the feedwater system.

The auxiliary feedwater system is composed of two 100% motor driven pumps and one 200% TDAFW pump which supply two trains of feedwater to each of the three steam generators. The pumps are normally aligned to take a suction on the primary plant demineralized water tank but can also be aligned to the river water system. The auxiliary feedwater line header isolation valves to each main feedwater line are locked open manual valves. The six throttle valves on the auxiliary feedwater injection lines are normally opened motor operated valves which can be controlled from the main control room or the remote shutdown panel. All three pumps start automatically. The start signal to the TDAFW pump opens two steam line trip isolation valves which supply steam to the turbine.

A dedicated auxiliary feedwater (DAFW) pump is available and is powered by a non-emergency diesel generator. The DAFW pump takes a suction from one of two independent tanks and injects water directly into the main feedwater header. The DAFW pump is independent of the auxiliary feedwater system. Local operator actions are needed to start the diesel, to start the DAFW pump and to establish the proper valve lineup which would result in the DAFW system being unavailable for a certain period of time after an accident.

5.1 Turbine Driven Auxiliary Feedwater Pump

The TDAFW pump is being well maintained and had adequate availability for 1987. Surveillance tests and the trending of results have adequately identified equipment problems which have been corrected by efficient preventive maintenance. Additional efforts to reduce the amount of condensate in the steam lines may reduce the preventive maintenance and result in a higher availability of the TDAFW pump.

The inspector evaluated the TDAFW pump availability based on entry into Technical Specification Action Statements. The availability of the TDAFW pump based on Technical Specification availability for 1987 was 0.987. The availability of the two motor driven pumps for 1987 were 0.999 and 1.00. The unavailability of the TDAFW pump was primarily due to preventive maintenance and inservice inspections. No pump failures were reported in the NPRDS data base for these pumps for the period between 1983 and the time of this inspection. The high availability of the TDAFW pump provides adequate assurance that the TDAFW pump will be available for accident mitigation.

A walk down of the system identified several deficiencies including leak by of the main steam trip valves MS-105A and MS-105B, the questionable operability of the steam traps based on the steady stream of condensate leaving the turbine casing drain, a leak on the lubricating oil system and poor housekeeping. The licensee had not identified the deficiencies and noted that the amount of water in the turbine casing was normal and had not adversely affected the availability of the turbine.

The housekeeping deficiencies were corrected in a timely manner, a work request was written to repair the oil leak and the licensee committed to evaluating the steam trap system. A steam trap was worked on two years ago, however repair parts were not available since the manufacturer had gone out of business. The licensee plans to investigate the potential for using steam traps similar to those in Unit 2 as replacements for the present Unit 1 steam traps.

The inspector concluded that the TDAF pump availability may be somewhat lower than the availability calculated. However, the inspector concluded that a lower availability of the pump is adequately compensated for by the installed DAFW pump system.

5.2 AFW Valve Availability

The inspector evaluated the availability of the valves associated with the TDAFW turbine and the auxiliary feedwater system. No valve failures occurred in 1987 and only minor corrective maintenance was conducted on the turbine governor valve. Failure of control signals to the feedwater pump recirculation valve made the valve inoperable but did not affect the availability of the system. Adequate surveillance and maintenance are being conducted on the valves in the system to assure adequate availability.

The licensee has procured equipment for conducting Motor Operated Valves (MOVs)testing and has tested the six auxiliary feedwater throttle valves as part of an initial MOV test program. The testing equipment has also been used to trouble shoot some valve problems, however, no decision has been made to use the equipment for diagnostic evaluations.

The terry turbine technical manual states that the governor valve can be damaged by low quality steam. The inspector noted that the steam lines connected to the governor valve had measurable condensate in them. Several preventive maintenance repairs have been performed on the governor valve. It was not clear whether the preventive maintenance was required to repair the damage resulting from the condensate. The inspector discussed the potential problem of having condensate in the steam lines and turbine casing with the maintenance department. The licensee representative agreed to review this concern and take measures to ensure system reliability by verifying the steam trap system operability and adequacy.

5.3 Surveillance and Maintenance

The operating surveillance tests were conducted in the required time frame and identified components which required preventive maintenance. Several documentation errors were noted by the inspector, such as recording the incorrect valve stroke time limit, recording the incorrect previous cycle time and making procedural changes using a line out instead of a permanent procedural change.

The Technical Assessment Group (TAG) provides quarterly reports on pump trends and semiannual reports on the trending of valve cycle times. Past reports have identified trends and made recommendations which have been reviewed and acted on by the Operations Assessment Group and the Inservice Surveillance Test Group. Reports for early 1987 were issued soon after the end of the trending period. Recent reports have been delayed for over a month after the end of the trending period. Issuing reports soon after the end of a trending period is important to obtain effective corrective action for identified concerns. Licensee management attention is warranted to assure timely issuance of trend reports.

The licensee uses technical manuals to develop maintenance programs which are modified based on operating and industry experience. The engineering department identifies additional vendor recommendations resulting from revisions to the technical manuals. The maintenance engineers are responsible for deciding which recommendations made in the technical manuals and made by the Engineering Department will be incorporated into the maintenance procedures. No documentation is required for the decisions made by the maintenance engineers. Several recommendations and cautions for the TDAFW pump have not been implemented. For example the recommendation that the overspeed trip valve be exercised weekly and the caution that low quality steam may damage the governor valve have not been implemented. The licensee committed to review the policy of not documenting engineering decisions made by maintenance engineers. This is an unresolved item. (50-334/88-08-03)

The I&C training program is INPO accredited while the maintenance training program is not. One aspect of an INPO accredited program is a clear definition as to which jobs a technician is qualified to perform. For both the I&C and maintenance departments the assignment of workers to specific jobs is the responsibility of the shop foreman, who relies on his past knowledge of individuals to assign tasks and not on a formalized training record. All technicians who were observed appeared to be adequately trained to perform the task assigned.

5.4 Conclusion

Based on this inspection, it is concluding that the Auxiliary Feedwater System is designed and maintained to provide high reliability. Except for the unresolved item, the license has established adequate measures to assure continued reliability for this system. The engineering, operating and maintenance personnel werè supporting the day-to-day care of this system appeared to be knowledgeable and adequately trainied.

6.0 Emergency Operating Procedures

A detailed review and walk down of the emergency operating procedures (EOPs) was performed during an NRC inspection the week of February 1, 1988. The inspection assessed the technical adequacy and conformance of the EOPs to the facility's NRC approved Writer's Guide. The above noted inspection found the EOPs to be technically adequate even though numerous deviations from the Writer's Guide were identified. The details of the inspection are documented in NRC Inspection Report 50-334/88-02.

During this inspection several scenarios that have potential for resulting in core melt were developed and run on the licensee's simulator. The purpose of the scenarios was to validate the importance of certain plant component failures in sequences that might lead to core melt and to evaluate whether the EOPs provide adequate direction for mitigation of the core melt sequences. The scenarios included various Loss of Electrical Power Events and Loss of Coolant Accidents. The details of the scenarios and the evaluation of the effectiveness of the EOPs to address these scenarios are presented below.

6.1 Loss of Electrical Power

A loss of a single 4 KV bus scenario was run for several different buses. The 1B, 1D and 1DF buses were deenergized on three separate scenarios. The EOPs were adequate to effectively stabilize the simulator without core melt.

A loss of all AC combined with the loss of a DC electrical bus scenario was run. The loss of the DC electrical bus complicated the recovery due to the loss of some instrumentation, however, the EOPs were adequate to effectively stabilize the simulator without core melt.

A loss of all electrical AC power scenario was run with the inspectors acting as the operators to evaluate the effectiveness of the EOPs. The inspectors used the EOPs in the simulator to stabilize the simulator within half an hour of the loss of the all electrical power, and to reestablish charging within half an hour of the restoration of an emergency bus. The use of inspectors in the operator positions provided confidence that the EOPs could be used to control the plant during a loss of all electrical power.

Two scenarios were run that simulated failures of equipment beyond the design basis of the facility. These highly unlikely scenarios were run to understand what failures have to occur to result in a core melt at Beaver Valley Unit 1. The EOPs were followed until all actions had been taken to stabilize the simulator. Discussions were then held with the operators, who were licensed on the facility, as to the expected results of the transients and possible actions which might be taken outside the EOPs to mitigate the effects of the transients. The details of the scenarios and discussions are presented below.

A loss of all AC electrical power combined with a 700 gpm loss of coolant accident from a reactor coolant pump seal scenario was run. The operators stated that the scenario would eventually result in core melt unless electrical power was restored. The operators discussed a possible equipment line up using the diesel fire water pump or the dedicated auxiliary feedwater pump and fire hose to inject river water into the reactor coolant system. This lineup is beyond the scope of any written procedure. The scenario confirmed that a core melt condition would eventually be reached unless actions were taken beyond the EOP during this highly unlikely event.

A loss of all AC electrical power combined with a loss of the turbine driven auxiliary feedwater pump and the dedicated auxiliary feedwater pump scenario was run. The operators stated that the scenario would eventually result in core melt unless auxiliary feedwater flow or electrical power was restored. The operators discussed using a possible equipment line up using the diesel fire pump and fire hose to inject river water into the steam generators. This line up is beyond the scope of any written procedure. The scenario confirmed that a core melt condition would eventually be reached unless actions were taken beyond the EOPs during this highly unlikely event.

6.2 Loss of Coolant Accidents (LOCA)

A pressurized surge line break scenario which resulted in a 700 gpm LOCA was run. The EOPs were adequate to stabilize plant conditions within the control limits specified by the EOPs. The inspector questioned whether there would be adequate net positive suction head (NPSH) for the low head safety injection (LHSI) pumps if containment pressure was at the low end of the control band at 8.9 psia. An accident analysis for a double ended rupture for the suction line to a reactor coolant pump, shows that there is about a 0.5 psi difference between the available NPSH (11.2 ft of water) and the required NPSH (10.6 ft of water) at an assumed containment pressure of over 11 psia. If the assumed containment pressure is reduced to

8.9 psia the available NPSH would be significantly less than the required NPSH. The licensee agreed to review the concern.

There is no engineering bases which assures that the containment pressure control band of 14 to 8.9 psia will provide an adequate NPSH to the LHSI pumps during the recirculation mode. This is an unresolved item (50-334/88-08-04).

A pressurizer surge line break combined with the failure of two boron injection tank supply valves and the hot leg injection valve scenario was run. The operators were able to restore injection flow to the primary through the cold leg injection valve even though the EOPs do not explicitly specify what steps should be taken. The inspector observed that the EOPs do not define explicitly the valves and priority of paths which should be used to establish injection flow. The licensee representatives acknowledged the inspector's observation and agreed to revise the procedures as needed.

A hot leg double ended shear combined with a failure of the containment sump valves to the LHSI pumps after the initiation of the recirculation mode scenario was run. The operators took the appropriate steps to line up an outside recirculation pump to the HHSI pump to keep the core covered.

6.3 Conclusions

The EOPs can be used to mitigate plant transients which may lead to core melt. However, minor issues such as the unresolved item in paragraph b 6.2 need to be resolved. At Beaver Valley Unit 1, the loss of electrical power events and the loss of coolant accidents complicated by valve failures do not result in core melt when actions are taken in accordance with the EOPs. The loss of all AC electrical power complicated by either a LOCA or a loss of all feedwater will result in core melt unless steps beyond the available written procedures are taken. However, these scenarios are well beyond the design bases of the facility.

7.0 Management Involvement, Operational Experience Feedback System and QA Involvement

7.1 Management Involvement

First line Supervisors of the activities reviewed and the Senior Management demonstrated awareness and involvement in maintaining high component and system availability. When concerns were identified the supervisors took conservative actions in the direction of safety. For example, when the inspectors identified a loose seismic support on diesel generator air start system, the licensee declared the affected diesel generator inoperable and took the actions required by the Technical Specifications. The overall site policy towards operations, maintenance and engineering activities was to assure optimum availability and reliability. The maintenance activities and tests were carefully planned to optimize down time resulting from such activities. As a result the systems reviewed during this inspection exhibited high availability.

The senior management is also interested in maintaining availability and reliability without compromising safety. The recently formed senior management appeared to be proactive and were taking actions based on the awareness of industry concerns and regulatory climate. Several actions are being developed to assure and maintain system reliability and availability. These include the efforts to reconstitute design criteria, to reconsitute the safety system functional evaluation and to perform a probabilistic risk analysis. Senior management discussed the action plans and major milestones for these efforts with the inspector. The licensee is carefully planning and evaluating these activities using pilot plans. Planned completion of these activities is spread over several years.

The licensee's present schedule is to complete between three and five systems each year. There are about fifty four systems at the unit, which includes sixteen safety related systems. The licensee plans to complete the safety related systems first. At the time of the inspection, the licensee was establishing design criteria for the auxiliary feedwater system, selected as a pilot project. The work was about two thirds complete. The inspector noted this level of involvement by the senior management as a licensee strength.

In summary, the licensee senior management has taken positive action to reconstitute the design basis of the unit, to maintain the availability of systems and components and to maintain a knowledgeable complement of personnel. This inspection team perceived this management involvement as a strength in licensee's activities.

7.2 Operational Experience Feedback

The inspector studied aspects of the licensee's administrative procedures for addressing operational experience. The objective of this study was to assure that component degradation or failure is promptly discovered and the root causes of failure is determined and corrected effectively. The main elements involved in this feedback loop are as follows:

Monitor

- collect operating experience
- identify potential problems such as excessive or repeated failures
- determine if a correctable, systematic cause exists

Correct

* perform root cause analysis
* determine options to cure problem
* select and implement cure

The inspector interviewed Maintenance Information Management personnel that maintain the Maintenance Work Request data base. The data base is fully operational and being used routinely. A number of data base requests were processed demonstrating the capability of data retrieval with good results. Special on-demand reports are processed for plant personnel. Also routine reports such as a "Problem Equipment Reports" are provided to plant management. Currently this report lists plant components that have received more than three MWR's in a years time. The inspector determined that the maintenance department studies this report and provides a written response that highlight recurring problems or problems correctable though changes in maintenance. The inspector was satisfied that management addresses these "Problem Equipment Reports."

The data base searches of the site specific MWR data base can be augmented by use of the NPRDS data base of the nuclear industry, the inspector determined that Beaver Valley is actively participating in NPRDS and that this computer base is fully accessible by trained personnel. The inspection team was provided with the NPRDS event reports for BV-1 for 1982 to 1987 for the preselected safety significant components (diesels, emergency buses, AFW pumps, charging pumps, SI pumps, and critical valves). This demonstrated the data retrieval capabilities at BV-1 and provided the team with the necessary component failure histories used, in part, to assess component availability.

The inspection team met with the plant manager and representatives for operations, maintenance, and engineering. The purpose of the meeting was to receive directly from management an understanding of the mechanisms used to monitor and correct problems. The purposes of the daily and weekly planning meetings were discussed as was the role of the various onsite and offsite committee.

The MWR data base and management response to the Problem Equipment Reports were discussed. The system of reporting and addressing operational problems was also discussed. Incident Reports and Unit Off Normal Reports that are prepared by plant staff (mainly operation personnel) were discussed. This formal report program is discussed in Chapter 13 of the Site Administrative Procedures. Critique meetings are convened to discuss an incident of significance. These meeting are structured to assure that safety implications are identified and that corrective action (both immediate and long term) to prevent repetition are implemented. The management is using this system effectively as evidenced by a number of separate initiatives that the inspector team reviewed such as improvements in the emergency diesel air start system and a concerted effort to find the root causes of inverter failure. Selected Incident Reports and Unit Off Normal Reports for 1987 were reviewed and provided further evidence that this formal reporting system is operating effectively to monitor and correct problems.

7.3 Quality Assurance (QA) Involvement In Assuring Availability

The Site QA organization conducts routine audits to assess the effectiveness of activities affecting availability of components. The inspector reviewed QA audits BV-1-87-06, 10, 14, on a selected basis. Audits contained attributes to verify the adequacy of procedures and activities required to assure operability of equipment. Audit 87-10 was to assess the effectiveness of the inservice testing program. Audit 87-14 was specifically conducted to assess the adequacy of the electrical and mechanical activities. These audits contained findings and observations relevant to safety and technical requirements. The response to the findings and observations from the audited organizations were timely and effective. Based on this review, the inspector concluded that the licensee's audit program has adequate measures to assure component availability.

8.0 Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. New unresolved items are discussed in paragraphs 4, 5 and 6 of this report.

9.0 Entrance and Exit Meeting

Licensee management was informed of the purpose and scope of the inspection at a pre-Inspection meeting on February 11, 1988 and at the entrance interview on March 21, 1988. The findings of the inspection were periodically discussed and were summarized at the mini-exit meeting on March 25, 1988 and the exit meeting on March 31, 1988. Attendees at the exit meeting are listed in Attachment 1 of this report.

At no time during the inspection was written material provided to the licensee by the inspectors. The licensee did not indicate that the inspection involved any proprietary information.

Attachment 1

Persons Contacted

Duquesne Light Company

*J. Bowden, I&C Supervisor, DLC
R. Caione, Electrical QC Inspector
*H. Caldwell, BVPS, Unit 1, DLC
*E. Coholich, Senior Licensing Supervisor, DLC
D. Corothers, Electrical Maintenance Supervisor
*P. Dearborn, Supv. Engr., DLC
*C. Ewing, Manager, Quality Assurance, DLC
*L. Freeland, Nuclear Operations Supervisor, DLC
D. Furgerson, Substation Operation Supervisor
*K. Grada, Manager Nuclear Safety, DLC
*K. Halliday, Superintendent of Engineering, DLC
S. Hovanec, Electrical Maintenance Engineer
H. Kahl, Principal Electrical Engineer
*J. Kasunick, Site Maintenance Director, DLC
L. Knapp, Senior Electrical Engineer
*F. Lipchick, Senior Licensing Supervisor, DLC
*R. Martin, Director, H/M Engineer, DLC
*D. Murcko, I&C Engineer, DLC
*S. Nass, Supervising Engineer
*T. Noonan, Plant Manager, DLC
*J. Rathke, Site I&C Support Coordintor, DLC
*C. Schmitt, Director, Electrical Engineering, DLC
*J. Sieber, Vice President Nuclear Group, DLC
*N. Tonet, Manager Nuclear Engr., DLC
J. Vassello, Director Licensing, DLC
F. Witkowsky, Senior Electrical Engineer
*R. Wittschen, Licensing Engineer, DLC
D. Williams, Senior Licensing Supervisor, DLC
J. Zebiley, Substation Operation Engineer

Stone and Webster Engineering Corporation

J. Cooper, Assistant Engineering Manager
R. Sibulkin, Assistant Lead Electrical Engineer
A. Mitra, Senior Electrical Engineer

U.S. Nuclear Regulatory Commission

*J. Beall, Senior Resident Inspector, NRC
J. Durr, Chief, Engineering Branch, NRC Region I
*J. Richardson, Deputy Director, DRS, Region I
*P. Tam, Project Manager, NRC Headquarters

*denotes those present at the exit meeting on March 31, 1988

The inspectors held discussions with other licensee administrative, technical and contact personnel.

Attachment 2

Documents Reviewed

A) Drawings

1) S&W Dwg. No. 11700-RE-1C-9 "Equipment one line diagram" dated 2/3/87
2) S&W Dwg. No. 11700-RE-1E-10 "Vital bus & DC one line Diagram" dated 1/3/87
3) S&W Dwg. No. 11700-RE-IV-12, 1W-5, 41X-5, 1Y-13, 1AE-13, "125 VDC one line diagram sheet 1 through sheet 5"
4) S&W Dwg. No. 11700-RE-1A-10 & 1B-11 "Main one line diagram, sheets 1&2"
5) S&W Dwg. No. 11700-RE-1D-10, 1E-11, & 1F-11 "4160V one line diagram, sheet 1 through sheet 3"
6) Duquesne Dwg. No. 8700-RE-100A-3 "4KV station service system" dated 7/23/87
7) S&W Dwg. No. 11700-01-RE-21BU "DC elementary diagram OCB92, station service transformers 1A&3A" dated 7/16/87
8) S&W Dwg. No. 11700-01-RE-21BV "DC elementary diagram OCB83, station service transformers 1B&2B" dated 7/16/87
9) S&W Dwg. No. 11700-01-RE-21EA "DC elementary diagram PCB331, main transformer breakers" dated 12/9/87
10) S&W Dwg. No. 11700-01-RE-21EB "DC elementary diagram PCB341, main transformer breaker" dated 12/9/87
11) S&W Dwg. No. 11700-RE-21AC-5B3 "Elementary diagram turbine control, sheet 1 of 3" dated 1/29/88
12) S&W Dwg. No. 11700-RB-2G-4 "Flow diagram, ventilation and air conditioning secondary plant sheet 4" dated 3/25/83
13) S&W Dwg. No. 11700-RE-1G-9, 1H-11, 1J-7, 1K-13 "480V one line diagram, sheet 1 through sheet 4"
14) 8700-RM53A, Rev. 11B8, Flow Diagram Gen. Fuel Anal. Air System
15) 8700-RM151A, Rev. 8, Emergency Diesel Generator Fuel and Air System
16) 8700-RE21BU, Rev. 7, Elem. Diag. Diesel Gen. #1 Engine Controls Sht 2
17) 8700-1.024-99, Cyberex Inverter Schematic
18) 8700-RE-21HY, Main Steam
19) 8700-RM-120A-11, Main Steam
20) 8700-RM-124A-15, Feed Water
21) 8700-RM-127A-16, River Water System

B) Procedures

1) PMP No. 1-36SS-BKR-1E "17E 5KV air circuit breaker inspection" Revision 8, dated 6/5/87
2) PMP No. 1-37SS-BKR-1E "480V Circuit breaker inspection General Electric AK-3A-25" Revision 0, dated 1/8/88
3) PMP No. 1-37SS-BKR-2E "480V station service system supply breaker inspection, AK-3A-505" Revision 0, dated 1/8/88
4) PMP No. 1-37SS-BKR-3E "480V circuit breaker overcurrent protection test" Revision 0, dated 9/9/87
5) PMP No. 1-37SS-BKR-4E "480V station service system supply breaker inspection" Revision 0, dated 1/8/88

6) PMP No. 1-37SS-BKR-5E "480V circuit breaker inspection, 1TE K-line" Revision 0, dated 9/9/87
7) MSP 39.01, "Battery No. 1 test and inspection" Revision 1 dated 3/7/88
8) MSP 39.02, "Battery No. 2 test and inspection" Revision 2 dated 3/7/88
9) MSP 39.03, "Battery No. 3 test and inspection" Revision 2 dated 3/7/88
10) MSP 39.04, "Battery No. 4 test and inspection" Revision 1 dated 3/7/88
11) BVT 1.1-1.39.1 "No. 1 Battery Charger load test and battery service test", 18 month frequency dated 12/31/87
12) BVT 1.4-1.39.6 "No. 1 station battery capacity test" 60 month frequency, dated 3/11/88
13) S&W specification no. BVS-191 "Specification for system station service transformers" dated 5/8/70
14) PMP 1-44VS-VNT-1E, Ventilation System, Rev. 3, 5/13/86
15) PMP 1-37SS-LINESTARTER Linestarter Inspection, Rev. 2, 5/12/86-1E
16) DLC Memo NDISMD:0689 J.R. Kasunitz to W.S. Lacey "Problem Equipment Report" dated 3/21/88
17) DLC Memo ND1DPO:1946 J.E. Matsks to T.G. Zyra "Problem Equipment Report - 1987" dated 1/22/88
18) Computer MWRS Printout for Selected 3/16/88 Printout Components 1/1/87 to 3/16/88
19) Data Sheets, Beaver Valley Power Station Unit 1 Diesel Generator Performance Data, 1985 thru 1987
20) Computer Printout NPRDS Data for Selected Components, 1983 thru 1987
21) Site Administration Procedure (SAP), Chapter 2, 3, Nuclear Division Organization
22) SAP, Chapter 3B, 3, Reporting Requirements
23) SAP, Chapter 3D, 3, The Maintenance Work Request
24) SAP, Chapter 2A, 0, Maintenance
25) SAP, Chapter 8B, 0, Instrumentation and Control
26) Operator Aid Rev. 32, Dated 2/12/88 Diesel Aid 1.36.4
27) Purchase Order Number: D035576, 37845 and 37935 to Combustion Engineering
28) MSP 13.08 issue 2, Rev. 0, L-100D Refueling Water Storage Tank Level Loop Channel II Test
29) MSP 24.08, Rev. 10, L-495 Steam Generator 1C Level Protection Channel II Test
30) OST 1.36.1, Diesel Generator No. 1 Monthly Test
31) Beaver Valley Unit 1 Technical Specification
32) USNRC Regulatory Guide 1.32 (Rev. 2)
33) OST 1.24.9, Issue 1, Rev. 56, Turbine-Driven AFW Pump (FW-P-2) Operability test
34) OST 1.24.4, Issue 1, Rev. 54, Steam Turbine Driven Auxiliary Feed Pump Test (1FW-P-2)
35) OST 1.24.1 AFW Pump Discharge Valve Exercise
36) Steam Generator Auxiliary Feed Pump, Ingersoll-Rand, Technical Manual, Audited 6/23/82 Received April 29, 1971
37) Completed Shift Foreman Shift Turnover Check Lists (Figure 48.1.C-1) for 1987
38) Completed Shift Supervisor Turnover Check Lists for 1987
39) Steam Driven Auxiliary Feedwater Pump Technical Manual

40) MWR 875084, TDAFW Pump Packing Leak
41) MWR 875905, Repaired Steam Leak on TDAFW Pump, Changed Oil
42) MWR 875116 Steam Leak on Turbine Casing
43) E-1, Loss of Reactor or Secondary Coolant
44) ECA-1.1, Loss of Emergency Coolant Recirculation

C) Reports

1) Semi-Annual Valve Review Report, August 31, 1987
2) Quarterly Pump Trend Report, November 10, 1987
3) September/October Operations Assessment Group Minutes, November 9, 1987
4) Engineering Memorandum No. 21,679; Review of TDAFW Technical Manual
5) Technical Evaluation Report (TER) 119 Terry Turbine Manual for FW-P-2