U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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50-412/93-27

LICENSE NOS.: DPR-66
NPF-73

LICENSEE: Duquesne Light Company
P. O. Box 4
Shippingport, Pennsylvania 15077

FACILITY: Beaver Valley Power Station, Units 1 and 2

INSPECTION AT: Shippingport, Pennsylvania

INSPECTION DATES: November 1 - 5, 1993

INSPECTORS:

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APPROVED BY:

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Areas Inspected: An announced safety inspection of the engineering program activities in support of plant operations. The inspection included a review of plant design changes/modifications, technical evaluation report (TER) process, licensee event reports (LERs), technical training, and the status of previously identified open items.

Results: TERs, LERs, and design changes/modifications reviewed by the NRC inspectors formed the basis for concluding that documents reviewed were technically accurate and presented valid resolutions. The training program for technical personnel was adequate and included a number of positive initiatives.

Nine previously identified open items were closed and three additional items were updated to reflect the current status.

DETAILS

1.0 PURPOSE

The purpose of this inspection was to assess the quality and adequacy of Beaver Valley's engineering support of plant operations. Areas examined included design changes and plant modifications, licensee event reports (LERs), technical staff training, staffing, and the status of previously identified open items.

2.0 ORGANIZATION

The Duquesne Light Company (DLC) management, staff, and engineering personnel continue to be located at the Beaver Valley site. The current engineering and technical staff consists of 165 individuals. There are ten vacant positions, with two new hires in process. The Nuclear Engineering Department continues to have six functional engineering organizations.

Discussions with the licensee indicate a gradual reduction to zero in the use of contract personnel over the next three years. This could have an impact on the performance of two groups which use a large number of contract personnel. Contract personnel constitute 50% of the Electrical Engineering Department and approximately 30% of the Nuclear Engineering Department.

3.0 ADMINISTRATIVE CONTROLS FOR ENGINEERING ACTIVITIES

The inspector reviewed selected administrative and engineering procedures, listed in Attachment 2, to determine whether the engineering activities were specified and controlled by approved procedures. Procedures reviewed by the inspector included those for initiating engineering work, station modification requests (SMR), design control work, safety evaluations, technical evaluations reviews, and prioritization of engineering work.

Based on this review, the inspector concluded that the licensee's procedures for engineering activities provided adequate guidelines and controls. Specific requirements were included to ensure that design changes and modifications comply with accepted industry standards and regulatory requirements. The procedures provided appropriate requirements and guidelines for the 10 CFR 50.59 screening and safety evaluations, verification of design input, calculations and final design, and proper approvals.

4.0 DESIGN CHANGES AND MODIFICATION PROGRAM IMPLEMENTATION

Procedure No. NEAP 2.2, Revision 6, establishes responsibility, requirements, and guidelines for implementing and control of design changes for BV Units 1 and 2. Minor modifications are addressed in Procedure No. NEAP 2.19, Revision 2. These procedures provided guidelines for the evaluation of approved station modifications requests (SMRs), preparation and conceptual designs, review and approval of modification packages, procurement, installation and post-modification testing of hardware. The procedure also outlined the requirements for other specialty groups (such as fire protection, environmental or seismic, etc.) when required.

The inspector reviewed selected design changes and modifications, listed in Attachment 2, to ascertain that the changes/modifications were performed in accordance with the requirements of the technical specification (TS), Code of Federal Regulation (10 CFR), the Safety Analysis Report, the BV's quality assurance program, and licensee procedures.

Based on this review, the inspector concluded that the design changes and plant modifications were complete, technically accurate, and supported by plant operational tests. The programs for completing the design changes and modifications were generally of good quality. The completed packages were found to have been reviewed by cognizant personnel and approved in accordance with established procedures and regulatory requirements.

5.0 LICENSEE EVENT REPORTS

The inspectors reviewed the licensee's incident reporting program to assure that the licensee event reports (LERs), listed in Attachment 2, were evaluated and controlled per established procedures and in accordance with regulatory requirements. Procedure No. NGAP 5.2, "Preparation of Incident Reports, Conduct of Critiques and Followup Actions," provided guidance for the preparation, review, and followup actions to identify and initiate root cause analysis of incidents.

The LERs were determined by the inspectors to be complete and technically accurate. A detailed indepth root cause analysis was performed, where applicable, in accordance with Attachment 4 of Procedure NGAP 5.2, Revision 2.

6.0 TRAINING

The procedures defining training were found in the Training Administrative Manual, Vol. 2, Chapter 5, Section 5.1; Nuclear Engineering Administrative Procedure (NEAP) 1.6, Nuclear Power Division Administrative Manual (NPDAM) 4.1; and the Quality Assurance Procedure 14. The training program consisted of several programs; Engineering Support Program (ESP) Orientation Training, Nuclear Engineering Department (NED) Indoctrination Training, ESP Position-Specific Training, and Continuing Training. The inspector reviewed the mandatory and continuing training of individuals from the entry-level engineer to a section director. NPDAM 4.1, which replaced Engineering Directive (ED) No. 42, described the division personnel's responsibilities for the establishment, implementation, and evaluation of needed onsite training. This procedure also emphasized the employees' obligation to participate actively in designated training and other activities that aid in improving performance.

The Training Administrative Manual described new orientation training procedures. Previously, the classroom orientation requirements were determined by a matrix that defined applicable instruction. All personnel, including contractors, are required to attend the entire orientation training. This training consists of classes in areas including reactor theory, auxiliary systems, thermodynamics, and instrument control theory. Newly hired engineering professionals and personnel who were qualified and performing satisfactorily in positions requiring position-specific training and qualifications are obligated to complete this training by the end of 1993. A waiver can be issued exempting personnel from certain training if the immediate supervisor feels that the classroom training standards have been met after reviewing previous training and experience, prior education, or observed performance. Approval of a waiver was subject to management acceptance and review.

The departmental training program consisted of a required reading indoctrination, position-specific training, and qualification. The indoctrination program has a reading checklist containing procedures, policies, and standards that are commonly used. Completion of this list assures staff familiarization with information needed to perform NED activities. The checklist emphasizes proficiency with the knowledge needed to perform activities required by their section. The position-specific checklist employed explanations on the use of departmental procedures and policies to accomplish their assigned duties and to appraise the aptitude of the individual.

Continuing training was formally conducted every quarter. This training keeps the staff current on modifications to the plant, procedures, or regulatory guidance. Additional training was given by miscellaneous reading checklists and optional attendance at the Technical Information Presentation Symposium (TIPS), an annual opportunity to exchange technical information concerning the nuclear facilities. The quarterly training and the miscellaneous reading was mandatory; often, the quarterly training was reinforced by an examination. An individual training roster was kept for each individual and periodic updates were sent to management, detailing the status of their staff's training.

The orientation program assured that individuals new to the division are knowledgeable and adept in the basic concepts of nuclear power generation. The continuing training program keeps the NED staff updated on changes onsite and in industry. Management demonstrated a strong commitment by actively promoting and participating in both mandatory and voluntary instruction. The department training program, in accordance with established procedures, was effective for ensuring individual development and qualification concerning administrative and technical issues important to the performance of the NED's responsibilities.

7.0 INFORMATION NOTICES

The Nuclear Safety Administration Manual (NSAM) Vol. II, Chapter 9, establishes the method for disposition of NRC Information Notices (INs). After receipt of the notices in the licensing section, an initial review was made to prioritize the notice and determine whether the review will be made in-house or by an outside organization. The IN was recorded in the Commitment Tracking System (CTS) with its due date and assigned reviewer. Upon evaluation of all relevant documentation and discussion with the appropriate site personnel, the examiner prepared a proposed position. The position paper was submitted for subsequent supervisory comments and approval. If needed, changes can be made by the reviewer and then resubmitted. Upon acceptance, the CTS will be updated, and the approved position routed to the applicable organizations. This CTS bimonthly report of the status of reviews ensures a timely response. The inspectors selected several Information Notices issued this year for review. The information received was adequately addressed per the procedures outlined in the NSAM.

8.0 CONCLUSION

Engineering continues to provide good support for plant operations. The quality of design changes, licensing event reports, and root cause analyses was determined to be good. Improvements were observed in the use of systems engineers to enhance plant operations.

The inspectors noted the licensee's extensive use of contract personnel and their planned reduction to zero use that could impact performance of the Nuclear/Electrical Engineering Department. BV currently uses 30-50% contract personnel.

9.0 STATUS OF PREVIOUSLY IDENTIFIED OPEN ITEMS

(Closed) Deviation No. 50-334/89-25-01 pertaining to the non-conforming Steam Generator Wide Range Level (SWGRL) Indicator.

Regulatory Guide (RG) 1.97, Revision 2, "Design and Qualification Criteria," Table 1, specifies independent and redundant instrument channels for Category 1 variables. The guide also specifies that transmission signals from these channels be through isolation devices that are part of the instrument loop and meet Category 1 criteria.

The inspector reviewed licensee correspondence dating back to the January 31, 1990, response to the deviation and including the resultant Supplemental Safety Evaluation issued by the commission on December 31, 1991. Following several discussions between the licensee and the NRC staff regarding corrective action to resolve the deviation, the licensee issued its proposed resolution in a letter to the NRC on January 24, 1992. NRC response, dated June 15, 1992, concluded that the proposed resolution, when implemented, would resolve the deviation. Compensatory measures were instituted by the licensee pending completion of the modification. The inspector reviewed the design change package, DCP

No. 1504, Revision 0, approved on September 4, 1992, to modify the SWGRL instrumentation to comply with regulatory requirements. Included in the review was the engineering design concept package containing the safety evaluation and design basis, the engineering design change turnover sheet and operational acceptance, and the open item list. Operational acceptance of the completed design change was on June 5, 1993.

The proposed changes to resolve the deviation by upgrading the SWGRL instrument loop to RG 1.97 standards noted in the January 24, 1992, letter were completed as stated. This item is closed.

(Closed) Unresolved Item No. 50-412/91-80-11 pertaining to completeness and adequacy of calculation for sizing Beaver Valley Unit 2 4.16 kV cables and lack of procedures to inspect cable after an overload trip of the feeder breaker.

Calculation, No. 10080-E72, Revision 2, allows the use of a 550°C upper limit for insulation temperature instead of the usual 250°C required by IPCEA standards for cables subjected to short-circuit currents. The basis for licensee acceptance of this criteria is contained in a letter (2DLC 23991), dated January 7, 1985. The 550°C maximum temperature ensures that a three-phase bolted or a phase-to-phase fault current cannot cause a cable to ignite since it is below the auto-ignition temperature (577°C) of the cable jacket material. An associated calculation, No. 10080-E-020, Revision 3, produced even higher temperatures than the allowed limit. However, in this case, the use of larger sized cables effectively reduced the maximum predicted temperature below the imposed limits. The inspector reviewed licensee Addendum 1 to Calculation No. 10080-E-020, Revision 3, written to address this issue, was approved on June 30, 1992. The addendum addresses the fact that AWG 1/0 copper cables were installed in parallel with existing AWG 1/0 cables, and that another AWG 1/0 copper cable was replaced with an AWG 4/0 copper cable. Attachment 1 of the calculation, pages 7, 11, and 23 show the new calculated cable temperature (206°C, 191°C, and 182°C) corresponding to the recommended changes in the conclusion section of the calculation. This cable change resolved the high temperature problem. The licensee also performed a review of all 4 kV single line drawings, 4 kV loads listed in "Electrical Motor and Load Equipment List by Equipment Identification," and all 4 kV cables listed in the 4 kV section of the EC-5 computer program to assure all 5 kV cables were addressed. Based on this review, the licensee concluded that all cables listed in the calculation and the modified cables were found to be acceptable.

In response to the lack of operating procedures requiring the testing and inspection of faulted 5 kV cables, the licensee provided the inspector with a copy of the Operating Manual. Chapter 36, Section 2, of this manual contains the requirement for testing the faulted 5 kV cables. The effective date of this section was May 22, 1989. Item 11 of this section states that, "No breaker will be reclosed following a fault trip until the fault has been analyzed and cleared." Item 45 of this section states, "If a three-phase fault occurs on any of the following loads, contact Electrical Maintenance to perform breaker inspection and cable insulation testing (CMP-2-75-2NS-7E) prior to returning load to service."

NOTE: It appears that the 2NS in the above procedure was a typing error. The designation should have been INS. The licensee indicated that because of this typing error, the procedure was placed in the inactive file, and may have been the reason why licensee personnel failed to provide this information to the NRC at the time of the EDSFI inspection.

This item is closed.

(Closed) Deviation No. 50-334/91-80-03 pertaining to three river water MOVs in the primary grade (PG) pump room that were located at an elevation that was below the station design flood limit of 730 feet.

The inspector reviewed the licensee response to the Notice of Deviation, dated May 8, 1992. The licensee indicated that this Deviation appears to be an oversight from the original plant design.

Documentation to indicate that the MOVs were capable of performing their design function in a flooded environment was not available. This item was determined to be a deviation from the Final Safety Analysis Report (FSAR) commitment which states, in part, that, "All safety-related equipment and connecting piping and wiring is either located above an elevation of 730 feet or adequately protected so that its function was unaffected by a flood to an elevation of 730 feet."

The inspector reviewed licensee procedure AOP-½-75.2, Issue 1A, Revision 2, that requires river elevations greater than 675 feet be monitored every four hours by an operator. In addition, the FSAR (page 2.3-41/2.3-43) indicates that the estimated time for the river water to rise from the mean sea level of 695 feet to the probable maximum flood (PMF) level was 23 hours.

Based on the above, an action statement was added by the licensee to the Abnormal Operating Procedure (AOP-½-75.2), "Acts of Nature Flood," to require the installation of plugs when the river water level reached 695 feet. The inspector verified the AOP change and availability of hydrotest plugs and installation tools in the storeroom. In addition, a review of site facilities was performed by the licensee to ensure adequate protection from PMF was completed on August 31, 1992. The technical requirement and engineering packages required to correct any deficiencies identified by the review were completed on December 31, 1992. This review involving Units 1 and 2, determined the adequacy of protection from PMF. The inspector noted that the protection seal program and materials were also reviewed by the licensee to ensure that seals below an elevation of 730 feet will function to prevent in leakage of water. Areas of Unit 1 were determined to be flooded, as noted in the FSAR, Section 2.7.3.2.3. No flood paths were identified for Unit 2. The inspector concluded the current penetration seal program and corrective actions taken by the licensee to be adequate. This item is closed.

(Closed) Violation Nos. 50-412/91-80-01 and 50-412/91-80-02 regarding inadequate circuit breaker interrupting capacity and coordination.

A review by the NRC EDSFI team of calculation No. 10080-E-62 determined that several safety-related circuit breakers, Heinemann Type CD and Airpax Type 209, had a short circuit interrupting capability of 5000A. This capability was insufficient to interrupt the required fault current loading of 8000A. The safety-related breakers identified were those in 125 Vdc distribution panel boards PNL*DC2-19 and 20 and in 4160 Vac switchgear 4KVS*2AE and *2DF. In addition, for the values of fault current available at certain breaker panels, the coordination between several Heinemann breakers and upstream ITE/Gould Type JL bus supply breakers could not be achieved for Unit 2.

The inspector reviewed the licensee's response to the Notice of Violation, dated May 8, 1992. The root cause analysis performed by the licensee indicated the information was in the calculation, but did not identify that there were deficiencies that needed to be resolved. The second factor identified in the licensee root cause analysis was that DLC had not done a technical review of the electrical calculation.

The inspector noted that the corrective steps taken by the licensee involved recalculating the short circuit currents in the safety-related 125 Vdc distribution system for Unit 2 per Design Analysis 10080-E-207, Revision 0. This calculation considered internal wiring resistances including battery intercell and intertier resistances and 4160 and 480 Vac switchgear internal wiring resistances to reduce the short circuit values presented in E-62. In addition, a more accurate short circuit current value for the battery, dependent on the total resistance of the circuit path per IEEE 946-1982, was included in E-62. This change in the short circuit value was due to the use of the nominal voltage (2.00 V) instead of the equalized voltage of 2.31V.

Results of calculation E-207 presented adequate protective device coordination for batteries 2-1, 2-2, 2-3, and 2-4 with few exceptions. The fault current limits to coordinate the switchboard breakers properly and the panel breakers were determined to be 1656A at the load circuit breakers. Based on this new calculation, coordination and adequate interrupting capability was achieved for all but the following breaker panels.

BAT*2-1 DC System	BAT*2-2 DC System
4KVS*2AE	4KVS*2DF
480VUS*2-8	480VUS*2-9
PNL*DC2-11	PNL*DC2-06

Resolution of the above discrepancies was addressed in Design Change Procedure (DCP) 2028. To obtain coordination between the above switchgear and panel breakers with the upstream switchboard breakers, resistances were added to the circuits to reduce the short circuit currents. As discussed above, the fault current was required to be reduced below 1656A at the load breakers. To achieve coordination, the licensee eliminated parallel feeder cables or increased cable lengths to provide additional resistances.

The inspectors reviewed DCP 2028, the associated 10 CFR 50.59 evaluation, and the calculations discussed above used to support this DCP. Based on this review, the inspectors concluded that the calculations included the proper load contributions and made proper allowances for determining short circuit current values. Protective coordination discrepancies were determined to have been properly resolved. Based on the above licensee actions, violations 50-412/91-80-01 and 50-412/91-80-02 are closed.

<u>(Open) Unresolved Item No. 50-334/91-80-06 and 50-412/91-80-06</u> regarding 125 Vdc short-circuit calculation.

The EDSFI team performed a review of the short circuit currents in battery systems to assess interrupting capability of circuit breakers in the 125 Vdc system. As stated in Inspection Report 91-80, the team examined BV2 calculation No.10080-E-62, Revision 4, which analyzed the short-circuit current available in battery systems 2-1 to 2-6. Pertaining to the calculation, the team noted that the calculation failed to include contributions from battery chargers and dc motors. In addition, short-circuit calculations were not available for Unit 1 battery systems. For these calculations the licensee indicated that they would be prepared as part of the design basis reconstitution program.

Subsequent to the team inspection the licensee reviewed the BV 2 calculation No. 10080-E-62, Revision 4, and verified the inclusion of dc loads including the 30 hp oil backup pump on battery system 2-5 and 60 hp bearing oil pump motor on battery system 2-6. During this inspection, the inspectors reviewed calculation No.10080-E-62, Revision 4, and one line diagram no. AA-No. 10080-RE-1AR, and verified that all significant loads were included in the short-circuit calculation.

Based on this review, this item remains open pending the completion of Unit 1 short-circuit calculations for the Unit 1 battery system including battery charger and motor contributions.

<u>(Closed) Unresolved Item No. 50-334/91-80-07</u> regarding steady-state loading analysis.

The EDSFI team reviewed calculation No.8700-DEC-E-048, Revision 0, dated January 13, 1989, to evaluate the loading on emergency diesel generator (EDG) no. 1 at each step of automatic sequencing and the period following automatic loading. This evaluation was performed for three accident scenarios. These scenarios included the design basis accident loss of coolant accident coincident with a loss of offsite power, a loss of normal power with a unit trip, and a safety injection signal with unit trip.

Based on review of this calculation, the team determined that the maximum coincident load for the worst-case scenario met the acceptance criteria and the calculated maximum continuous load was below the continuous rating of 2600 kW for the EDG. However, the team's review identified several areas of concern. These concerns included potential overloads following automatic sequencing with minimum margin between the calculated loads and imposed limits, selection criteria for brake horsepower values, auxiliary feedwater pump motor capability, and load values presented in the FSAR.

In response to these concerns, the licensee revised calculation No.8700-DEC-E-048 incorporating the most conservative values for brake horsepower (bhp) between the calculated bhp requirements based on system flows or head and efficiency data from the manufacturer's certified test curves.

As discussed in inspection report 91-80, the licensee identified incorrect entries for mechanical input values of the load study. Based on a detailed evaluation performed by Duquesne Light Company (DLC), overall calculated EDG loading was reduced. The maximum loading was determined to be 2676.2 kW anticipated at 225 seconds into a LOCA coincident with loss of offsite power accident. The acceptance criteria of calculation 8700-DEC-E-048, Revision 1, allows a maximum coincident (short time) load of 2745 kW that is 90% of the diesel 30-minute rating of 3050 kW. The inspectors noted that these values were well within the 2000 hour rating of the machine and were accurately reflected in the revised FSAR tables.

The licensee presented operations Procedure No. 10M-10.4.A, "RHR System Startup (Plant Cooldown) and Operation" to address the potential for overloading the diesel following automatic sequencing. This procedure contained administrative controls to ensure that diesel loading is limited prior to adding additional load. Specifically, this procedure limits loads to 2500 kW prior to starting an RHR pump.

Based upon the licensee's revised steady-state loading calculation, established administrative controls to prevent overloading emergency buses being supplied by the EDGs, and updated FSAR to reflect accurately diesel generator loading and available margins, the inspectors concluded that the licensee adequately addressed the EDSFI team's concerns. Based on review of DLC's corrective actions discussed above, this item is closed.

(Open) Unresolved Item No. 50-334/91-80-08 and 50-412/91-80-08 regarding EDG transient loading analysis.

A review by the EDSFI team of the Unit 1 EDG transient loading capability revealed that the licensee's analysis was based upon a generic Dead Load Pickup Capability Curve and a letter from the EDG manufacturer. This curve and letter combined, analyzed the automatic step loading of a sample EDG to which DLC was to compare the postulated Beaver Valley accident loading steps. As long as these postulated values were enveloped by a sample loading case, it was concluded that the voltage drop and recovery time to 90% were acceptable.

The team questioned the applicability of the manufacturer's curve and noted that no calculations existed to support the design basis of the sampled cases. In addition, no EDG test as described in Sections 8.6.2 and 8.6.3 of the FSAR was available for review at the time of the inspection.

Subsequent to the inspection the licensee performed analysis No. 8700-E-241, Revision 0, "Diesel Generator Dynamic Loading Analysis." The purpose of this analysis was to demonstrate through computer modeling that both EDGs at Beaver Valley 1 can successfully accelerate and support the required emergency loads during accident and loss of offsite power conditions. The computer model evaluated the dynamics for motors being started and motors that had been previously started and were running.

The inspectors noted that this analysis concluded that both Unit 1 EDGs could successfully accelerate and support the required emergency loads. However, no review was made to verify the computer model and the effects of voltage regulator and governor action. This item remains open pending NRC review of licensee analysis No.8700-E-241, assumptions within this calculation, and actual test results to validate this analysis as well as the corresponding analysis for Unit 2.

<u>(Open) Unresolved Item No. 50-334/91-80-09 and 50-412/91-80-09</u> pertaining to load sequencing during EDG testing.

While performing a review of the sequencing of safety-related loads on the emergency diesel generators (EDGs) following a loss of offsite power, the EDSFI team identified that when the EDG is in parallel with the offsite transmission system during testing and a degraded grid condition or loss of offsite power occurs, the immediate addition of emergency bus loads would occur. The team was concerned that the addition of these loads would occur prior to the governor changing from the droop to isochronous mode of operation and voltage regulator changing from the parallel to isolated mode thereby allowing the diesel generator to be overloaded.

Following the inspection, DLC performed an analysis of this event. During this review, DLC identified that Beaver Valley Unit No. 1 EDG has a Woodward type UG-8 governor. This governor is a mechanical governor and does not have separate parallel and isochronous modes of operation. DLC performed Design Verification Report 8700-E-243, Revision 0, to address the addition of emergency bus loads during EDG testing. Results of this transient stability analysis indicated that the EDG had adequate capability to recover and operate during load rejection transients including a trip from reverse power or undervoltage scenario presented in the analysis.

The inspectors reviewed the above analysis for Unit 1 and noted that a similar analysis for Unit 2 had not been completed at the time of this inspection. This item remains open pending NRC review of the licensee's assumptions and completed analyses of both units for evaluation of the EDG and motors' operation during load sequencing and a degraded grid or loss of offsite power event.

<u>(Closed) Unresolved Item No. 50-334/91-80-13</u> regarding auxiliary feed pump capability.

The EDSFI team performed a review of manufacturer's pump characteristic curves to determine the power demand on the emergency diesel generators for the three accident scenarios listed in the FSAR. This review identified that the steam generator auxiliary feed pump had been operating above its continuous rating value of 400 hp with a service factor of 1.15 (460 hp). This increase in pump load had been due to pump operation at run-out flow conditions to the steam generator during check valve testing. However, the EDSFI team's concerns were the capability of the pump to operate at run out conditions in the event of a feedwater line break, the effects of previous testing on motor operability, environmental qualification with motor operation above nameplate rating, and the unanalyzed protection scheme for motor overload conditions.

Subsequent to the inspection, DLC engineering performed a design calculation to determine the adequacy of the auxiliary feedwater pump motors to supply the required horsepower with the assurance that motors will operate safely during the higher loading condition for the required operating time. This calculation, No.8700-DEC-0121, Revision 0, utilized design values for temperatures in the auxiliary feedwater pump area resulting from the maximum heat load generated under design basis accident conditions when the pumps are required to operate per calculation No.8700-DMC-2651, Revision 0.

Under accident conditions, auxiliary feedwater pumps FW-P-3A and FW-P-3B are required to deliver a maximum shaft output of 495 and 485 brake hp (bhp), respectively. Motor output required after ten minutes of an accident condition will be reduced to 384 bhp by operator actions to regulate auxiliary feedwater flow for FW-P-3B. Results of the analysis presented in calculation No.8700-DEC-0121 demonstrated the capability of these motors to run the pumps at the higher bhp requirement without environmental qualification reduction or pump degradation. This was substantiated by a letter from the pump vendor, Ingersoll-Dresser, dated April 29, 1993. Based on review of the protection scheme for these motors and the Westinghouse information letter (IL) 41-102E, the licensee has increased the 'B' pump motor relay tap setting from 3.0 to 3.5. This setting change prevents the motor from tripping during a Design Bases Accident. This tap setting change was based on a calculated required current of 58.7 amps on the EDG for FW-P-3B with a relay setting of 60 amps +/- 5% tolerance. The new relay setting will provide protection for currents up to 70 amps +/- 5% tolerance to ensure reliability.

The inspectors reviewed operations test procedures Nos. OST 1.24.6, OST 1.24.8, and 1 OST-24.14 A and B to verify that future auxiliary feedwater pump testing will not be performed at run-out conditions. Precautionary notes were established within the procedures to prevent the motor driven auxiliary feed pumps from cavitation by limiting flow to the steam generators to 550 gpm. The inspectors concluded that based on the satisfactory results of the analysis performed to address the adequacy of the motor size and motor capability, this item is closed.

(Closed) Unresolved Item No. 50-412/91-80-16 pertaining to EDG rear bearing cooling water piping.

During an inspection of the Unit 2 EDGs, the EDSFI team noted that a plastic pipe section (8" long x 1¼" diameter) used for the cooling water supply to the rear bearing of the EDGs appeared to have been replaced. The team was concerned that a failure of these lines could render the EDGs inoperable as a result of a rear bearing failure, loss of jacket cooling water, or shorting of the generator due to water spray from a broken pipe. At the time of the EDSFI, the licensee had no analysis clearly demonstrating the capabilities of the pipe for its application and environment.

In response to the team's concerns, DLC performed calculation No.10080-DLC(P)-835-XD, Revision 0, "Seismic Pipe Stress Calculation - Unit 2 - Diesel Generator Outboard Bearing Cooling Water PVC Pipe Connections." This calculation analyzed the polyvinyl chloride (PVC) pipe for pressure, thermal, deadweight, and seismic loading. This analysis was performed per the rigid classification of piping as originally installed.

The inspector noted that the stress evaluation was performed using the QA Category I in-house software program, Nupipe Run, to determine actual and allowable values for stresses including deadweight, seismic, thermal, and combinations thereof. Maximum outlet temperature of the coolant from the bearing (116 degrees F) as well as the inlet temperatures (113 degrees F) were found to be well below the maximum temperature for the PVC pipe (140 degrees F).

Assumptions used throughout this analysis included: the lowest strength PVC piping; worst-case environmental temperatures; seismic and operating conditions for loading; and conservative design values on the piping. Based on this analysis, the inspectors concluded that the PVC piping is acceptable for its application. This item is closed.

(Closed) Unresolved Item No. 50-334/91-80-17 regarding relay testing.

During the EDSFI inspection, the team witnessed a calibration of a Class 1E undervoltage relay used to start the unit 1 "A" EDG. This relay was an ASEA Brown Boveri type 47H. During this test, the relay exhibited a setpoint drift that appeared to be temperature related due to the test environment. In addition, the team reviewed a letter (RBRB142) from the vendor to the licensee, dated September 6, 1991, which discussed a setpoint drift problem with relays 27-VB100 and 27-VC100. These relays are General Electric type CFV and are used to detect undervoltage on the supply to the reactor coolant pump. This letter suggested setting the relays outside their technical specification limits prior to testing to ensure they would drift to their correct band by testing time. During this inspection the licensee stated that no relay setpoints had ever been adjusted prior to testing. Engineering Memorandum No. 101626 responded to this letter but recommended relay changeout and drift data requirements be incorporated into the monthly maintenance surveillance procedures (MSPs).

Subsequent to the team inspection, the licensee revised a total of 31 MSPs and 2 relay calibration procedures involving Type 47H, 47D, and CFV relays to address the environment in which relays are tested. These procedure revisions included precautions to take local room temperatures and drafts into account when setting these types of relays. In addition, all relay personnel were instructed on the potential for relay drift due to temperature differences between the location where the relay is set and where the relay is installed and tested. These drifts were attributed to cooling of the coils due to a delay between the time of coil deenergization and the time the as-found setpoint was checked. This conclusion by the licensee was substantiated by the relay manufacturer's instruction manual GEI-15536G which stated that the relay setpoint would increase after heating from energization.

The inspectors reviewed relay calibration procedures 1RCP-5-PC and 1/2RCP51-PC and completed maintenance surveillance procedures (MSP), listed in Attachment 2, for relay types CFV and 47H. These procedures were found to include the necessary precaution statements for relay testing environments. Also, the inspectors verified that all personnel performing relay testing had received training pertaining to this concern of relay drift. In addition, the inspectors noted that over the past several months, since incorporating these measures, relay drift values have continually decreased from the setpoint values.

Based on review of the licensee's corrective actions to address relay drift due to testing conditions, the inspectors concluded adequate measures had been established to minimize drift values. This item is closed.

10.0 EXIT MEETING

Licensee management was informed of the scope and purpose of the inspection at the entrance interview on November 1, 1993. The findings of the inspection were discussed with licensee representatives during the course of the inspection and presented to licensee management present at the November 5, 1993, exit interview. The licensee acknowledged the inspection findings detailed in this report. The licensee did comment on the reduction in the use of contract personnel, stating they are aware of the concern but were unable to provide information at this time on its impact on engineering work load.

ATTACHMENT 1

Persons Contacted

Duquesne Light Company

	J. Auckney	Electrical Engineer
	J. Baumler	Director, Audit and Surveillance
	V. Corbett	Senior Engineer
*	P. Dearborn	Engineering Supervisor
*	K. Grada	Manager, Quality Service Unit
*	K. Halliday	Director, Electrical Engineering
*	E. Knapek	Senior QA Specialist
*	F. Lipchick	Senior Licensing Engineer
	D. MacBride	Systems Engineer
	D. McClain	Manager, Maintenance Engineering and Assembly
*	S. Nass	Director, Nuclear Engineering Services
*	T. Noonan	General Manager, Nuclear Operations
	V. Palmiero	Engineering Supervisor
	M. Patel	Electrical Engineer
*	M. Siegal	Manager, Nuclear Engineering
*	J. Starr	Supervisor, Engineering Management
*	D. Szucs	Senior Engineer, Licensing
	R. Zabowski	Director, Systems Engineering

U.S. Nuclear Regulatory Commission

*	P. Sena	Resident Inspector

* Denotes personnel present at exit meeting of November 5, 1993.

ATTACHMENT 2

Documents Reviewed

LICENSEE EVENT REPORTS

93-001-00, Unit 1 - Condition Outside Design Basis, Main Steam Isolation Valve Closure not considered in original design

93-002-00, Unit 1 - Engineered Safety Feature Actuation, Inadvertent tripping and automatic starting of river water pumps

93-003-00, Unit 1 - Control Room Habitability Air Bottle Subsystem Manually Isolated

93-004-00, Unit 1 - Potential Small Break Loss With Coolant Accident Radiological Release

93-005-00, Unit 1 - Degraded Charging Pump Due to Incorrect Solenoid Valve Quality Assurance Classification

93-010-00, Unit 1 - Missed Technical Specification Surveillance on Safety Systems Accumulator Sample

93-011-00, Unit 1 - Engineered Safety Functions Actuation, Letdown Isolation during Unit Startup

93-012-00, Unit 1 - Reactor Startup With a Wide Range Containment Hydrogen Analyzer Inoperable

93-001-00, Unit 2 - Design Stress For The Auxiliary Feedwater System Exceeded Due to Waterhammer

93-002-01, Unit 2 - Reactor Trip and Safety Injection Due to Comparator Card Failure In a Main Steam Pressure Channel

93-004-00, Unit 2 - Steam Generator Blowdown Isolation While Trouble Shorting dc Ground

MAINTENANCE SURVEILLANCE PROCEDURES

1MSP-36.05B-E
1MSP-36.05C-E
1MSP-36.05A-E
1MSP-36.09-1A-E
1MSP-36.09-1B-E
1MSP-36.09-1C-E
1MSP-36.53A-E, and
1MSP-36.55-E

DESIGN CHANGE PROCEDURES

DCP-1053, Unit 2 -	Trip Main Feedwater Pump 2 FWS-P-21B following Reactor Trip
DCP-1531, Unit 1 -	Replacement of obsolete vital bus inverters and computer vital bus and static switch
DCP-1618, Unit 1 -	Replacement of ITE-27/59H relays
DCP-1401-1, Unit 1 -	GE AK air circuit breaker modification
DCP1598, Unit 1 -	CD-11 type relay replacement for existing CD-8 relay to maintain coordination on emergency bus for large motors
DCP-2045, Unit 2 -	Replacement of narrow range RTD
DCP-1986, Unit 1 -	Installation of source range detector
DCP-2012, Unit 1 -	Replacement of Magnehelic Instrument w/test connector

ADMINISTRATIVE/ENGINEERING PROCEDURES

NEAP 2.9, Revision 2, "Minor Modifications"
NEAP 1.6, Revision 2, "NED Training Program"
NEAP 2.1, Revision 6, "Station Modification Requests"
NEAP 2.2, Revision 6, "Design Change Control"
NEAP 3.3, Revision 1, "Contract Engineering Services"
NGAM 7.4, Revision 2, "Temporary Modifications"
NGAP 7.8, Revision 0, "Station Modification Control"
NGAP 5.2, Revision 2, "Preparation of Incident Reports"
NGAP 2.17, Revision 0, "Workload Priority Systems"